STATE OF MICHIGAN

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES

FOR 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

NOTICE OF AMENDED PROPOSAL FOR DECISION

The attached Amended Proposal for Decision is being issued and served on all parties of record in the above matter on January 29, 2026.

Exceptions, if any, must be filed with the Michigan Public Service Commission, 7109 West Saginaw, Lansing, Michigan 48917, and served on all other parties of record on or before February 17, 2026, or within such further period as may be authorized for filing exceptions. If exceptions are filed, replies thereto may be filed on or before February 26, 2026.

At the expiration of the period for filing exceptions, an Order of the Commission will be issued in conformity with the attached Amended Proposal for Decision and will become effective unless exceptions are filed seasonably or unless the Proposal for Decision is reviewed by action of the Commission. To be seasonably filed, exceptions must reach the Commission on or before the date they are due.

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES
For the Michigan Public Service Commission

Jonathan F. Thoits

Digitally signed by: Jonathan F. Thoits
DN: CN = Jonathan F. Thoits email = ThoitsJ@michigan.gov C = US O = MOAHR OU = MOAHR - PSC
Date: 2026.01.29 15:09:46 -05'00'

Jonathan F. Thoits
Administrative Law Judge

January 29, 2026
Lansing, Michigan

TABLE OF CONTENTS

AMENDED PROPOSAL FOR DECISION **1**
I. **1**
PROCEDURAL HISTORY AND OVERVIEW OF THE RECORD **1**
II. **9**
LEGAL STANDARDS **9**
III. **10**
TEST YEAR **10**
IV. **17**
RATE BASE **17**
A. Net Utility Plant 17
1. Distribution Background and Overview 19
a. High Voltage and Metro Distribution 39
b. Low Voltage Distribution 97
c. LVD Capacity 183
d. Grid Modernization 200
2. Streetlighting Capital Expenditures 222
3. Generation Capital Expenditures 227
a. Overview 227
b. Fossil Generation and Ludington Pumped Storage 230
c. Hydroelectric Generation 278
d. Battery Storage 279
e. Decommissioning and Coal Ash Disposal 284
4. Facilities Capital Expenditures 285
a. Control/Dispatch Center(s) 285
b. Other Equipment and Emergent Repairs 293
5. Fleet Services 296
a. Vehicle Replacement Plan 297
b. Vehicle Expansion Plan 303
c. Fleet Electrification 305
6. IT and Security Capital Expenditures 312

a. Overview 312
b. IT Adjustments 314
7. Demand Response Capital Expenditures 366
8. Customer Experience and Operations Capital Expenditures 386
9. Corporate Services Capital Expenditures 387
10. Transportation Electrification Plan 387
11. Accumulated Provision for Depreciation 406
B. Working Capital 407
1. Cash Balance 407
2. Accrued Taxes 418
3. Cloud Computing Deferred Costs 421
C. Total Rate Base 422
V. 422
CAPITAL STRUCTURE AND RATE OF RETURN 422
A. Test Year Capital Structure 423
B. Overall Rate of Return 450
1. Long-Term Debt Balance 450
2. Short-Term Debt Balance 450
3. Deferred FIT Balance 451
4. Other Capital Structure Balances 451
C. Cost Rates 452
1. Return on Common Equity 452
a. Consumers 455
b. Staff 464
c. Attorney General 473
d. ABATE 481
e. CUB 490
f. Walmart 498
g. Rebuttal 502
h. Recommended ROE 506
2. Long-Term Debt Cost Rate 542
3. Short-Term Debt Cost Rate 544

4. Other Cost Rates 546
5. Overall Rate of Return 546
VI. 546
ADJUSTED NET OPERATING INCOME 546
A. Jurisdictional Revenues and Sales Forecast 547
1. Sales Forecast 547
2. Total Electric Operating Revenues 567
B. Fuel, Purchased, and Interchange Power Expense 567
C. Other O&M Expense 570
1. Distribution O&M Expense 570
a. Electric Operations 570
b. Electric Engineering & Support 632
2. Line Clearing O&M Expense 636
3. Service Restoration 662
a. Service Restoration Expense 662
b. Service Restoration Resiliency Fund 674
c. Extraordinary Storm Accounting 676
4. Generation O&M Expense 692
5. Customer Experience O&M Expense 702
6. Corporate Services O&M Expense 702
7. Information Technology O&M Expense 716
8. Employee Benefits Expenses 721
9. Incentive Compensation Expense 722
10. Inflation Rates 740
a. Rates 740
b. Productivity Offsets to Inflation 741
D. Depreciation and Amortization Expense 754
E. Taxes 755
F. Allowance for Funds Used During Construction 760
G. Calculation of Adjusted Net Operating Income 761
VII. 762
COST OF SERVICE, RATE DESIGN, AND TARIFF ISSUES 762
A. Cost of Service 762

1. Distribution Cost Allocation and the EAC Report 768
2. Advanced Metering Infrastructure Cost Allocation 782
3. MAOAM Cost Allocation 795
B. Rate Design 797
1. Large Economic Development Rate 800
2. Data Centers 817
C. Electric Vehicle Rate 821
D. Heat Pump Rate 831
E. Tariff Issues 836
1. Service Connection Fee 836
2. AMI Opt-Out 843
VIII. 849
OTHER ISSUES 849
A. Distribution Investment Recovery Mechanism 849
B. Distribution System Planning and Analysis 867
C. Clean & Equitable Grid 882
D. Capital Spending Overview 916
E. Historical System Performance 920
F. Distribution Deferral Mechanism 926
G. Low-Income Assistance Programs 928
1. Shut-off Protection Plan 935
2. Winter Protection Plan (WPP) 936
3. Percent of Income Payment Program (PIPP) 938
4. Low-Income Assistance Credits 943
H. Pension/OPEB Volatility Mechanism 944
I. Disconnection Regression Analysis 945
J. State Reliability Mechanism 955
K. Virtual Power Plants 965
L. Transmission Coordination with METC 988
M. Separate Campbell Plant Docket 991
N. Accounting Requests 994
1. SAP S4/HANA Regulatory Asset Approval 995
2. LVD Line Clearing Ramp-up Deferral 997
3. Surge Capital Spending on Pole Replacements 1007

O. Wire Down 1009
XI. 1011
CONCLUSION 1011

STATE OF MICHIGAN

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES

FOR 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

AMENDED PROPOSAL FOR DECISION

I.

PROCEDURAL HISTORY AND OVERVIEW OF THE RECORD

On June 2, 2025, Consumers Energy Company ("Consumers" or "Company") filed an electricity rate application requesting a $436 million revenue increase, plus an additional $24.3 million for distribution deferral, and other relief.

Consumers, Staff, and potential intervenors attended the July 2, 2025, prehearing conference. The Michigan Attorney General (Attorney General) intervened by right and intervention was granted to the Association of Businesses Advocating Tariff Equity ("ABATE"); Michigan Environmental Counsel ("MEC"); Citizens Utility Board of Michigan ("CUB"); Sierra Club; Natural Resources Defense Council ("NRDC"); the Ecology Center, Environmental Law & Policy Center, Union of Concerned Scientists, Vote Solar (collectively, the "Clean Energy Organizations" or "CEO"); Great Lakes Renewable Energy Association ("GLREA"); Hemlock Semiconductor Operations LLC,

Solar Technology LLC, Urban Core Collective ("UCC"), Walmart Inc., Michigan Electric Transmission Company ("METC"), Energy Michigan, Michigan Energy Innovation Business Council ("MEIU"), The Institute For Energy Innovation, Advanced Energy United, Foundry Association of Michigan, Kroger Co., Michigan Cable Telecommunications Association. The parties agreed to a schedule complying with the time limits of MCL 460.6a.[1] On June 5, 2025, the Protective Order, which was entered, pursuant to which certain testimony and exhibits relied upon by the parties were deemed Confidential Information and entered under a separate record.

In keeping with the schedule established at the prehearing, Staff and intervenors Attorney General; ABATE; MEC; Solar Technology; UCC; Walmart; METC; Energy Michigan; MEIU, and CEO filed direct testimony and supporting exhibits on September 30, 2025. CUB filed revised direct testimony on October 9, 2025. Consumers, Staff, ABATE, GLREA, Energy Michigan, Solar Technology, Kroger, MEIU, and LBWL-MSU collectively filed rebuttal testimony on October 21, 2025. On October 21, 2025, Consumers filed revised direct testimony of several witnesses, and on November 11, 2025, revised rebuttal testimony.

Evidentiary hearings were held on November 4, 2025, November 5, 2025, November 6, 2025, and November 10, 2025.

During the hearing, Consumers offered the testimony of the following employees:

1. Heidi J. Myers, Executive Director of Revenue Requirements and Regulatory Affairs (Direct and Rebuttal);

[1] Section 6a(5) of Public Act 286 requires the Commission to issue its final order within 10 months following receipt of a complete rate case filing, lest the application be considered approved. MCL 460.6a(5).

2. Stacy H. Baker, Director of Technology Portfolio Office (Direct and Rebuttal);

3. Marc R. Bleckman, Executive Director of Financial Planning and Analysis (Direct and Rebuttal);

4. Richard T. Blumenstock, Executive Director of Electric Supply Engineering (Direct and Rebuttal);

5. Eugene M.J.A. Breuring, Principal Sales Forecasting Analyst, Financial Planning & Analysis (Direct and Rebuttal);

6. Ann E. Bulkley, Principal, Brattle Group (Direct and Rebuttal);

7. Jessica R. Byrom, Director of Customer Strategy (Direct and Rebuttal);

8. Thomas P. Clark, Executive Director of the Clean Energy Project Development (Direct);

9. Laura M. Connolly, Director of Regulated Pricing, Rates and Regulation Department (Direct and Rebuttal);

10. Amy M. Conrad, Director of Compensation Operations (Direct and Rebuttal);

11. Patrick D. Daley, Director of Revenue Requirements (Direct and Rebuttal);

12. Emily A. Davis, Principal Rate Analyst, Pricing section, Rates and Regulation Department (Direct and Rebuttal);

13. Matthew J. Foster, Principal Rate Analyst (Direct and Rebuttal);

14. Alex M. Gast, Manager, Customer Regulatory Strategy, Customer Experience Department (Direct and Rebuttal);

15. Brittani A. Gray, Senior Tariff Analyst, Rates and Regulation Department (Direct)

16. Kendra K. Grob, Senior Manager, Benefits (Direct);

17. Quentin A. Guinn, Capital Asset Strategy Manager (Direct and Rebuttal);

18. Megan L. Hayward, Director, High Voltage Distribution System Planning (Direct and Rebuttal);

19. Michael P. Kelly, Executive Director, Electric Distribution Strategy (Direct and Rebuttal);

20. Jon J. Koetje, e Director of Engineering, Procurement, and Construction Project Management for Fossil Generation (Direct);

21. Scott A. McPhail**,** Director of Grid Automation (Direct and Rebuttal);

22. Ashley E. Meschke, Director of Lean Strategy (Direct);

23. Megan L. (Metz) Jerore**,** Director of Electric Supply Operations and Power Supply Cost Recovery, Electric Supply Organization (Direct and Rebuttal);

24. Jeffrey A. Myrom, Manager, Asset Strategy, Gas Strategy Department (Direct and Rebuttal);

25. Jennifer M. Partlan, Director of Low Voltage Distribution System Planning (Direct and Rebuttal);

26. Daniel A. Schmoekel, Senior Strategy Manager for Electric Distribution (Direct and Rebuttal);

27. Andrew R. Snider, Executive Director of Electric Operations (Direct and Rebuttal);

28. Sara E. Stewart, Senior Manager of Forestry Operations (Direct and Rebuttal);

29. Caitlin M. Tetrick, Executive Director of Total Rewards & Workforce Strategy (Direct);

30. Brian J. VanBlarcum, Tax Director, Corporate Tax Department (Direct and Rebuttal);

Through these witnesses, Consumers entered into evidence Exhibits A-1 through A-201, and A-204 through A-230 inclusive.

Staff offered testimony from the following witnesses:

1. Theresa L. McMillan-Sepkoski, Audit Specialist, Revenue Requirements Section, Regulated Energy Division (Direct);

2. Kirk D. Megginson, Financial Specialist, Revenue Requirements Section, Regulated Energy Division (Direct);

3. Robert F. Nichols II, Manager, Revenue Requirements Section, Financial Analysis and Audit Division (Direct);

4. Shannon Rueckert, Auditor, Revenue Requirements Section (Direct);

5. Ryan Boutet, Public Utilities Engineer, Electric Operations Section, Energy Operations Division (Direct);

6. Jessica Duell, Public Utilities Departmental Analyst, Electric Operations Section, Energy Operations Division (Direct and Rebuttal);

7. Ally Durfee, Public Utilities Engineer, Electric Operations Section, Energy Operations Division (Direct);

8. Nicholas M. Evans, Manager, Electric Operations Section (Direct and Rebuttal);

9. Laura Maio, Public Utilities Engineer, Energy Cost Recovery & Generation Operations Section, Energy Operations Division (Direct);

10. Jacob G. Martus, Public Utility Engineer, Infrastructure Section, Gas Safety and Operations Division (Direct);

11. Jing Shi, Public Utilities Engineer, Electric Operation Section, Energy Operations Division (Direct);

12. Joshua S. Towslee, Departmental Analyst, Interconnection and Distributed Energy Resources Section, Energy Operations Division (Direct);

13. Hunter Hansen, Public Utilities Engineer, Data Access, Privacy & IT Section, Customer Assistance Division (Direct);

14. Brittney Klocke, Senior Analyst, Data Access, Privacy and IT Section, Customer Assistance Division (Direct);

15. Emma Zichi, Analyst, Data Access, Privacy and IT Section, Customer Assistance Division (Direct);

16. Kevin S. Krause, Gas Cost of Service Specialist, Regulated Energy Division, Rates and Tariff Section (Direct);

17. Mark J. Pung, Departmental Specialist, Rates and Tariff Section, Regulated Energy Division (Direct);

18. Michelle L. Schreur, Manager, Income Analysis Unit, Revenue Requirements Section, Regulated Energy Division (Direct);

19. Madison S. Todd, Departmental Analyst, Rates & Tariff Section, Regulated Energy Division (Direct);

20. Timothy G. Witt, Auditor, Revenue Requirements Section, Regulated Energy Division (Direct);

21. Allan D. Freeman, Assistant to the Division Director, Energy Resources Division (Direct and Rebuttal);

22. Marceline A. Champion, Public Utilities Engineer, Resource Optimization and Certification Section, Energy Resources Division (Direct);

23. Paul R. Ausum, Economic Analyst, Resource Adequacy & Forecasting Section, Energy Resources Division (Direct);

24. Anna N. N. Schiller, Public Utilities Engineer Specialist, Distribution Planning Section, Energy Resources Division (Direct);

25. Elaina M. Braunschweig, Departmental Analyst, Rates and Tariff Section, Regulated Energy Division (Rebuttal).

Through these witnesses, Staff entered Exhibits S-1 through S-4, S-6 through S-8, S-8.1 through 8.8, S-9.1 through S-9.2, S-10.1 through S-10.28, S-11.0 through S-11.1, S-12.0 through S-12.3, S-13.1 through S-13.7 and S-13.9 through S-13.11, S-14.1, S-15.0 through 15.12, S-16.1 through S-16.3, S-17, S-18, S-19.0, S-20, S-21.

The Attorney General provided the direct testimony of Sebastian Coppola, an independent business consultant, and Exhibits AG-1 through AG-83.

ABATE provided the direct testimony of Christopher C. Walters, Jessica A. York and Colin T. Fitzhenry; direct and rebuttal testimony of James R. Dauphinais, and rebuttal testimony of Brian C. Andrews, consultants in the field of public utility regulation, and Exhibits AB-1 through AB-21.

MEC and NRDC provided the direct testimony of Scott Reeves, a consultant in the field of clean energy markets, policies and programs. MEC and CUB provided the direct testimony of Tyler Comings, an economist. CUB provided the direct testimony of Matthew Bandyk, a consultant in the fields of energy and environmental issues. MEC, NRDC, Sierra Club and CUB provided the direct testimony of Richard J. Bunch and Caroline Palmer, consultants in the fields of clean energy, environmental issues, and

utility regulation. NRDC, Sierra Club, and CUB provided the testimony of Douglas Jester, a consultant in the field of utility industry regulation. MEC, NRDC, Sierra Club and CUB entered the following exhibits: MEC-1 through MEC-5, MEC-6C, MEC-7 through MEC-10, MEC-11C, MEC-12 through MEC-13, MEC-14C, MEC-15 through MEC-23, MEC-27, MEC-28, MEC-29C, MEC-30 through MEC-34, MEC-35C, MEC-36 through MEC-50, CUB-1 through CUB-30.

Solar Technology provided the direct and rebuttal testimony of Michael P. Gorman, a public utility regulation consultant, and entered exhibits SLT-1 through SLT-3.

UCC provided the direct testimony of Sergio Cira-Reyes, the Climate Justice Catalyst at UCC and Tabitha Williams, president of Parents for Healthy Homes, and entered exhibits UCC-1 through UCC-112 and UCC-201 through UCC-205.

Walmart provided the direct testimony of Matthew T. Lyon, Senior Manager, Utility Partnerships - Regulatory, and entered exhibits WAL-1 through WAL-4.

Michigan Electric Transmission Company provided the direct testimony of Michael Fleck, Director.

Energy Michigan provided the direct and rebuttal testimony of Alexander J. Zakem, a consultant, and entered exhibits EM-1 through EM-5.

MEIU provided the direct and rebuttal testimony of Sophia Schuster, a Policy Principal with the Michigan Energy Innovation Business Council and the Institute for Energy Innovation, and John D. Albers, Director, Advanced Energy United, direct testimony of Brett Sproul, a Regulatory Policy Principal with Advanced Energy United,

and entered exhibits MEIU-1.1 through MEIU-1.4, MEIU- 2.1 through MEIU 2.13, and MEIU-3.1 through MEIU 3.10.

The Ecology Center, The Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar (collectively, the "Clean Energy Organizations" or "CEO") provided the direct testimony of William D. Kenworthy, Senior Regulatory Director – Midwest for Vote Solar, Lee Shaver, Senior Energy Analyst, Union of Concerned Scientists, and Boratha Tan, Vote Solar, Senior Regulatory Manager, and entered exhibits CEO-1 through CEO-9.

GLREA provided the direct and rebuttal testimony of Richard Boehnke, consultant in the filed of virtual power plants, and exhibits GLREA-1 and GLREA-3.

Kroger provided the rebuttal testimony of Jared Robertson, a Senior Consultant for Energy Strategies, LLC.

In accordance with the established schedule, Consumers, Staff, the Attorney General, ABATE, MNSC[2], Solar Technology, UCC, Walmart, Michigan Electric Transmission, Energy Michigan, CEO, GLREA and Kroger filed initial briefs on December 5, 2025.[3] All of those parties except Walmart, Michigan Electric Transmission, and Kroger also filed reply briefs on December 23, 2025.

---

[2] The Michigan Environmental Council (MEC), Natural Resources Defense Council (NRDC), Sierra Club, and Citizens Utility Board of Michigan (CUB) (collectively, MNSC).

[3] As customary, the scheduling memo provided various requirements for the briefs to be filed, including providing that each brief shall contain a table of contents, listing the subject headings of the brief, including the points of argument, in the order of presentation according to the points of argument set forth by the utility, with the numbers of the pages where they appear in the brief. The memo also states that on or before the date for the filing of rebuttal testimony, the utility shall serve on all parties and the ALJ the points of argument which will be included in the utility's brief(s), and that all other parties shall include the same points of argument headings and subheadings in the same order as set forth by the utility in its list of points of argument. On October 21, 2025, Consumers served its points of argument on the parties. Unfortunately, however, Consumers' initial brief did not contain the same points of argument which it prepared and served on the parties. As such, Consumers initial brief does not conform to the requirements for the briefs, and in the future the non-conforming brief shall be stricken from the record.

In order to ensure compliance with the statutorily imposed timeframe for deciding this case, MCL 460.6a(5), the evidence and arguments necessary for a reasoned analysis of the disputed issues are expressly addressed in the Proposal for Decision. However, all the evidence presented in this case was considered, along with the arguments made by the parties based on the evidence.

II.

LEGAL STANDARDS

The Commission is required to set rates that are just and reasonable.[4] The rate-making process necessarily "involves a balancing of the investor and the consumer interests."[5] As such, the rates established should not be "so low as to be confiscatory or so high as to be oppressive."[6] Thus, the customer "should not be required to pay rates that will yield an extraordinary profit to the utility" and the stockholders of the utility "are at all times entitled to a fair return on their investment."[7]

The Commission applies the preponderance of the evidence standard when making findings of fact or weighing conflicting evidence.[8]

In considering whether rates are just and reasonable, it is the result reached, and not the methods employed, that is controlling.[9] As such, the Commission is not bound

---

[4] MCL 460.557(4); *City of Detroit v. Michigan Public Service Commission*, 308 Mich 706, 716, 14 N.W.2d 784 (1944).
[5] *Fed Power Comm v Hope Natural Gas Co*, 320 US 591, 603; 64 S Ct 281; 88 L Ed 333 (1944); *City of Detroit, supra,* at p. 716.
[6] *City of Detroit v. Michigan Railroad Commission*, 209 Mich 395, 433, 177 N.W.2d 306 (1920).
[7] *City of Detroit v. Michigan Public Service Commission*, 308 Mich 706, 718, 14 N.W.2d 784 (1944).
[8] Case No. U-18014, Order, January 31, 2017, p. 8.
[9] *Hope Natural Gas Co*, 320 US at 602 ("Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling.").

by any particular method or formula in determining what is fair and reasonable.[10] The Commission has broad discretion in the rate-making process, except regarding constitutional issues.[11]

III.

TEST YEAR

A test year is the starting point for establishing just and reasonable rates for both the regulated utility and its customers.[12] A test year is used by the Commission to establish representative levels of revenues, expenses, rate base, and capital structure for use in the rate-setting formula.[13] The selection of an appropriate test year has two components: determining a 12-month period to be used for setting the utility's rates, and determining how the Commission should establish values for the various revenue, expense, rate base, and capital structure components used in the rate-setting formula.[14] The Commission may use different methods in establishing values for these components, provided that the result is a determination of just and reasonable rates for the company and its customers.[15]

Section 6a(1) of Act 286, MCL 460.6a(1), provides that a utility may use projected costs and revenues for a future consecutive 12-month period to develop its requested rates and charges. In a case where a utility decides to base its filing on a fully

---

[10] *Hope Natural Gas Co*, 320 US at 602 ("The Commission was not bound to the use of any single formula or combination of formulae in determining rates."); Case No. U-15244, Order, December 23, 2008, p. 12, citing *Meridian Twp. V. City of East Lansing*, 342 Mich 734, 749, 71 N.W.2d 234 (1955).
[11] *Northwestern Nat. Cas. V. Ins. Com'r*, 231 Mich App 483, 488, 586 N.W.2d 563 (1998)("An agency's decision that 'is in violation of statute or constitution' is not authorized by law."); Case No. U-21806, Order, September 30, 2025, p. 5 (ALJ notes "the Commission's broad discretion in ratemaking proceedings in the absence of any issues raising constitutional concerns.")
[12] Case Nos. U-15768 and U-15751, Opinion and Order, January 11, 2010, p. 9.
[13] *Id.*
[14] *Id.*
[15] *Id.*

projected test year, the utility bears the burden to substantiate its projections.[16] If the utility cannot or will not provide sufficient support for a particular revenue or expense item (particularly for an item that substantially deviates from the historical data) the Staff, intervenors, or the Commission may choose an alternative method for determining the projection.[17]

In this proceeding, Consumers proposed using the 12-month period ending April 30, 2027 as the projected test year and the 2024 calendar year as the historical year.[18] Ms. Myers stated that the Commission has for many years approved the use of projected test years, noting that in Consumers Energy's gas rate case, Case No. U-21806, the Commission's September 30, 2025 Order again approved the use of a projected test year despite being presented with the same arguments from intervening parties as those made in this case.[19]

Mr. Dauphinais asserted that Consumers' use of a projected test year is a major driver of the Company's proposed rate increase in this proceeding.[20] Based on a comparison of Consumers' own historical and projected test year calculations for this case and its six most recent general rate cases, he argued that Consumers 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

---

[16] *Id*.
[17] *Id*.
[18] 3 Tr 1046, 1040.
[19] 3 Tr 1839. Citation omitted.
[20] 6 Tr 3639.

year.[21] He added that the use of a projected test year allows Consumers to begin recovering "costs" before those costs have been verified as being real and prudently incurred.[22]

Mr. Dauphinais further testified that the use of a projected test year causes customers to experience rate increases sooner than they would using a historical test year, eliminates the incentive for Consumers to contain costs, and allows Consumers to project capital expenditures and expenses that either Consumers has not irrevocably committed to making or otherwise can avoid if it finds it advantageous to do so.[23] He adds that this unreasonably benefits Consumers' shareholders at the expense of Consumers' customers to the extent the Staff and intervenors are unable to uncover and bring to the Commission's attention problematic projected costs before they are incorporated into Consumers' base rates.[24]

Mr. Dauphinais asserted that the Company has collected excess revenue because of its use of a projected test year, as shown in five of its most recent general rate case filings wherein Consumers has reported a revenue sufficiency of approximately $13 to $26 million for its historical test year.[25] He argues that this means that, in those years, Consumers received revenues $13 to $26 million higher than necessary to earn its authorized rate of return during those historical years.[26]

---

[21] 6 Tr 3639-3640.
[22] 6 Tr 3640-3641.
[23] 6 Tr 3641.
[24] Id.
[25] 6 Tr 3642, Table JRD-3 (6 Tr 3640).
[26] Id.

Mr. Dauphinais asserted that the Commission is not required to set rates using a projected test year.[27] He added that the utility bears the burden to substantiate its projections when using a fully projected test year, and 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."[28] He stated that the referenced alternative method should be the use of the historical test year amount for that item, adjusted for only known and measurable changes to the amount for that item.[29]

Mr. Dauphinais concluded by recommending that, if the Commission allows Consumers to use a projected test year in this case, the Commission should "continue to be vigilant" with respect to ensuring the expenses and investments being projected by Consumers are "truly expenses and investments that are necessary to provide reliable electric service at lowest reasonable cost", the Commission should ensure that Consumers is "irrevocably committed to incur its projected expenses and investments or otherwise cannot avoid them", and that the Commission should ensure that Consumers' projected investments and expenses are "precisely quantified with respect to both amount and the specific quarter" in which Consumers will incur these investments and expenses.[30]

In rebuttal, Ms. Myers countered that Mr. Dauphinais does not assert that all of Consumers' projected costs were not sufficiently supported nor does he provide an

---

[27] 6 Tr 3643. Citation omitted.
[28] Id., citing Case No. U-15768, Order, January 11, 2010, p. 9.
[29] Id.
[30] 6 Tr 3644.

explanation for what he believes constitutes a known and measurable change.[31] She adds that the use of a projected test year provides the calculation of rates necessary during the period for which the rates will be in effect, and that this is the most accurate way to set rates and provides Intervenors with an opportunity to comment on Consumers' plans for spending prior to the dollars being spent.[32] She asserted that 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.[33]

Ms. Myers argued that Consumers has an incentive to hold spending levels at amounts approved in rates and to spend efficiently, noting that once rates are established, Consumers is left to manage the business within those rates inclusive of risks that are outside the control of Consumers such as weather impact on sales.[34] She added that setting rates based on historical spending is inferior as it only allows for review of spending after it has already occurred.[35] She noted that 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 Consumers and an inefficient use of a finite amount of dollars available to invest in the system.[36] She stated that while it may be true that rate requests would be different if Consumers were required to rely on a historical test year for rate relief, it would not remove the need for rate relief but would only

---

[31] 3 Tr 1839-1840.
[32] Id.
[33] Id.
[34] 3 Tr 1841.
[35] Id.
[36] Id.

unfairly delay it.[37] She argued that establishing a built-in regulatory lag as proposed by Mr. Dauphinais is inconsistent with the Michigan Law providing for rates to be set using projected test years.[38]

In its initial brief, ABATE argues that given these endless and exorbitant requests the Commission should be vigilant in ensuring Consumers' cost projections are adequately supported and should base Consumers' revenue requirement on historic costs where Consumers' does not meet that burden.[39]

ABATE notes that the Commission stated in its Order in Case No. U-20561 that the record should lend itself to a comparative review of the reasonableness and prudence of the projections and that historical data may be the controlling factor in circumstances that clearly demonstrate that it is a more fair and reasonable reflection of the utility's cost of service, relative to projected data."[40] ABATE argues that the Commission is not required to base utility rates on projected costs and may instead utilize historic data when it is a more fair and reasonable indication of the utility's costs.[41]

Quoting comments filed in Case No. U-21637, ABATE asserts that numerous entities representing myriad interests have explained that the fully projected test year does not serve the best interests of utility customers.[42] ABATE argues

> The Company itself effectively acknowledged this issue, stating that "[i]f 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

---

[37] 3 Tr 1842.
[38] Id.
[39] ABATE Initial Brief – Corrected, p. 2.
[40] Id., p. 4, quoting Case No. U-20561, Order, May 8, 2020, p 13.
[41] Id.
[42] Id., p. 4-5, quoting Comments filed in Case No. U-21637.

> Company and an inefficient use of a finite amount of dollars available to invest in the system." (Myers 2 Tr 1362.) In other words, the use of projected test years to establish revenue requirements entails cost recovery which may not have been appropriate. While Consumers apparently considers such excessive revenue recovery appropriate, the point that this argument entirely elides is that *Consumers should not recover costs for unreasonable and imprudent expenditures*. In contrast to this basic principle of establishing just and reasonable rates, the Company has asserted that it is more efficient for the Company to receive rate revenue for items which ultimately "should be disallowed from rates," than for the Commission to review the reasonableness and prudence of the Company's actual expenditures. This turns the entire paradigm of regulating utility rates on its head and prioritizes utility revenue collection over the establishment of accurate and reasonable customer rates.[43]

This PFD finds that ABATE offers compelling testimony and argument in favor of the Commission using historical test year data, adjusted for known and measurable changes, instead of projected test year revenue and expense projections. This testimony and argument is consistent with the comments made by other parties that a fully projected test year favors the utility over the interests of utility customers.[44] However, after having considered the filed comments, the Commission stated that "the statutory mandate makes the projected test year an option for the filing utility", and that, in light of the statutory latitude afforded to the Commission, "it is reasonable for the Commission to continue to consider the evidence on an issue-by-issue basis and determine whether the most competent, material, and substantial evidence supports a result based on historical rather than projected amounts."[45] In this regard, this PFD notes that the Commission has previously stated as follows:

> In a case where a utility decides to base its filing on a fully projected test year, the utility bears the burden to substantiate its projections. . . If the Staff or intervenors find insufficient support for some of the utility's

[43] Id., p. 7. Emphasis in original.
[44] See comments filed in Case No. U-21637.
[45] Case No. U-21637, Order, July 10, 2025, p. 38.

> projections they may endeavor to validate the company's projection through discovery and audit requests. If the utility cannot or will not provide sufficient support for a particular revenue or expense item (particularly for an item that substantially deviates from the historical data) the Staff, intervenors, or the Commission may choose an alternative method for determining the projection.[46]

Accordingly, this PFD recommends the adoption of Consumers' proposed test year.

IV.

RATE BASE

A utility's rate base is the value of the utility's property on which it is permitted to earn a specified rate of return. Rate base consists of the capital invested in used and useful plant, less accumulated depreciation, plus the utility's working capital requirements. In its application, Consumers projected a total electric rate base of $15.367 billion, adjusted to $15.330 billion in its brief reflecting the removal of $250 million in ARP-Collaboration capital expenditures for the 12 months ending December 31, 2025, that the Company agreed to in rebuttal.[47] Staff projected a rate base of $15.209 billion in its brief, which is $121,466,000 less than the Company's updated projection of $15,330,358,000 in its rebuttal testimony. The difference is due to a $121,466,000 reduction to net utility plant and no reduction to working capital.[48]

A. Net Utility Plant

Net plant is the primary component of rate base, and its key elements are total utility plant (plant in service, plant held for future use, and construction work in progress

[46] Case No. U-15768, Order, January 11, 2010, p. 9-10.
[47] Consumers brief, p. 191, Appendix B1; Exhibit A-12.
[48] Staff brief, p. 3.

(CWIP)) less the depreciation reserve, which includes accumulated depreciation, amortization, and depletion.

Various categories of capital expenditures included in rate base are broken out and discussed below. However, before discussing disputed issues regarding rate base investments, it is appropriate to reiterate the Commission's standards for decision-making. As previously discussed, utility may use projected costs and revenues for a future test year when requesting an increase in rates, see MCL 460.6a(1), but the Commission has made clear that a utility must establish the credibility of its projections.[49] If a utility seeks approval for a projected cost, it should provide sufficient evidence to demonstrate that the specific project and its cost are reasonable and prudent, and it must also show by a preponderance of the evidence that the cost will actually be incurred before the end of the test period.[50] Further, if a utility fails to provide sufficient support for its method of forecasting a particular item or category of expense, then the Commission may choose an alternative method for determining the projection.[51] Additionally, the Commission has consistently rejected the use of

[49] See June 12, 2012 order in Case No. U-16794, p. 13 (Rejecting the argument that the Commission must necessarily accept a utility's projection and stating that a utility must supply the Commission with enough evidence to support a finding that the costs requested are just and reasonable).
[50] January 13, 2017 order in Case No. U-18014, pages 8-9 ("Moreover, in the case where the company seeks approval for a projected cost, the company must not only provide sufficient evidence to demonstrate to the Commission that both the specific project and its cost are reasonable and prudent, but it must also show by a preponderance of the evidence that the cost will in fact be incurred before the end of the test period.").
[51] January 11, 2010 order in Case No. U-15768, pages 9-10; see also September 8, 2016 Order, Case No. U-17895, page 4.

contingency amounts in projections, as well as the use of so-called “placeholders” through which the utility seeks to fill in missing details or costs after the initial filing.[52]

Finally, it should be emphasized that an adjustment to the utility’s projection for a particular item in this PFD is not necessarily the equivalent of a permanent disallowance of that expenditure. Rather, most adjustments made to capital expenditure items reflect a finding that the specific projected cost is currently not supported by sufficient evidence; thus, reasonable and prudent expenditures may be recovered in a future proceeding.

In this case, Consumers has subdivided net plant into the following programs: 1) Distribution; 2) Streetlighting; 3) Generation; 4) Information Technology; 5) Security; 6) Electric Vehicles; 7) Operations Support; 8) Fleet Services; 9) Corporate; 10) Customer Experience & Operations; and 11) Demand Response.[53]

Disputes concerning these programs, along with certain subprograms or spend categories are addressed below. Given the strict time limits mandated for completion of rate cases, programs or subprograms, or spending categories that were not disputed are generally not addressed in this PFD.

1. Distribution Background and Overview

Mr. Kelly provided an overview of the Company’s electric distribution strategy, which detailed how Consumers measures electric reliability performance, as well as

[52] December 17, 2020 order in Case No. U-20697, pages 9, 19-20 (Listing several previous Commission orders rejecting contingency costs while denying a request for such costs, and also rejecting cost placeholders or the presentation of costs only later in rebuttal or in response to discovery).
[53] Exhibit A-12, Schedule B-5.

past actual and projected future reliability performance, based on the impact of the distribution investments proposed in this rate case.[54]

Mr. Kelly explained that Consumers has produced a series of five-year distribution plans known as the Electric Distribution Infrastructure Investment Plan (EDIIP), the first of which was filed in March 2018, in Case No. U-17990. Grid Archetypes were introduced in the Company's second plan to consider LVD circuit characteristics beyond reliability metrics to prioritize investments, ensuring that investments were optimally made across the Company's distribution system and across different capital spending programs to ensure that no section of the grid was inadvertently left behind.[55] Grid Archetypes are updated every three to four years. The most recent iteration of the five-year grid plan—the third EDIIP—was filed in September 2023, in Case No. U-20147 and is referred to as the "Reliability Roadmap" or distribution system plan (DSP) in this PFD.[56]

Mr. Kelly stated that the Reliability Roadmap, as modified in this case, defines the Company's current distribution objectives and goals, and the investment plans to meet those objectives and goals, which were reflected in the proposed spending levels in this proceeding.[57] According to Mr. Kelly, in the Reliability Roadmap, the Company established four key objectives for its electric distribution system: safe; reliable and resilient; clean and equitable; and, competitive.[58] Mr. Kelly asserted that the Company plans to meet these objectives through the multi-year investment plan established in the

---

[54] 3 Tr 1375-1624.
[55] 3 Tr 1386.
[56] 3 Tr 1379.
[57] 3 Tr 1380.
[58] 3 Tr 1380-1381.

Reliability Roadmap, which incorporated a variety of best practices and forward-looking approaches to achieve reliability through increased line clearing, asset hardening, rehabilitation, and automation.[59]

According to Mr. Kelly, the Reliability Roadmap is a continuation and an expansion of the Company's long-term distribution strategy of: 1) excelling at the basics, and 2) building for the future by effectively modernizing the electric grid to deliver safe, reliable, and affordable electricity to customers today, and into the future.[60] Mr. Kelly, explained that "excelling at the basics" consists of investments in and maintenance of core traditional infrastructure, like poles, wires, and substations, all of which improve electric system reliability under normal operating conditions, and resiliency under extreme conditions;[61] while "building for the future" consists of enabling the transition to cleaner energy resources, including integration of DERs, and increasing automation of the system, using advanced grid technologies to provide the Company's customers with the technology and tools to take greater control over their energy supply, reduce system waste, and optimize DER use.[62]

Mr. Kelly stated that the Company made minor adjustments to the 2023 Reliability Roadmap for this case, updating information to reflect another year of actual historical reliability data, and to extend projected investments by another year into the future and address issues highlighted by intervenors.[63] The 2023 Reliability Roadmap took seriously the Commission's findings on reliability, particularly regarding the need to

[59] 3 Tr 1381.
[60] 3 Tr 1381.
[61] 3 Tr 1382.
[62] 3 Tr 1382.
[63] 3 Tr 1389.

improve reliability in the face of increasingly severe weather. As a result, Mr. Kelly averred, the Reliability Roadmap evaluated multiple plausible future scenarios, including a future with increasing severity and frequency of storms, rather than assuming historical weather patterns would continue in the future, and then laid out a multi-year investment plan to address asset deterioration and maintain asset health against identified risks while also hardening assets against increasingly severe weather, so that customer reliability improved even if conditions worsened.[64] Mr. Kelly pointed out that in any of the scenarios modeled, climate change would result in more severe weather and extreme heat, creating increasing reliability and resiliency challenges for the distribution system. Regardless of climate policy, the Company's modeling projected an increase of 10-15% in severe weather-related outages by the early 2030s, compared to 2020 levels. The Company emphasized that the most critical issue to focus on was reliability and resiliency in the face of storms, which was a more immediate threat.[65]

Mr. Kelly testified that to address reliability metrics other than SAIDI excluding MEDs (x-MEDs), the Company proposed a new Vulnerable Communities Resiliency Plan ("VCRP") with a specific goal of boosting communities in economically vulnerable areas into the second quartile of all-weather SAIDI.[66] Mr. Kelly further noted that the Commission established all-weather SAIDI as a metric for its new performance based ratemaking (PBR) framework in Case No. U-21400; and as the PBR framework is fully

[64] 3 Tr 1390.
[65] 3 Tr 1391.
[66] 3 Tr 1421.

implemented, the Company expects to develop even more investments intended to improve all-weather SAIDI and meet the Commission's expectations.[67]

Mr. Kelly also testified that the Company has not met the Commission's Service Quality and Reliability Standards for CEMI-4 in recent years. CEMI-4 was designated as a metric in the PBR framework, and the Company increased its investment in its LVD Repetitive Outages sub-program to specifically target this metric.[68]

Mr. Kelly testified that this rate case translates particular years of the distribution strategy and investment plan of the Reliability Roadmap into specific investment programs, sub-programs, investment categories, and projects.[69] He stated that the Reliability Roadmap did not address investment unrelated to improving reliability and resiliency or address asset health risk. In particular, investments in New Business, Asset Relocations, and Demand Failures were not discussed in significant detail in the Reliability Roadmap.[70]

Mr. Kelly then turned to the Commission-directed third-party audit and review of all equipment and operations of the Company's distribution system.[71] The third party, Liberty Consulting Group, spent about a year evaluating the Company's distribution system and distribution plans before filing its report (Liberty Audit) with the Commission.[72] He noted that the Company was agreeable to some of the Audit's recommendations regarding distribution investment strategy, noting the recommendation that the Company place less emphasis on asset age when deciding

---

[67] 3 Tr 1421.
[68] 3 Tr 1422.
[69] 3 Tr 1423.
[70] 3 Tr 1423.
[71] 3 Tr 1392-93.
[72] 3 Tr 1392.

whether to replace assets. However, the Company does, in some cases, use age as one of many risk factors in determining whether to replace an asset.[73]

The Liberty Audit also recommended the Company slow the pace of investment as defined in the 2023 Reliability Roadmap and evaluate different timeframes for how the Company could meet its reliability goals. In response, the Company agreed to supplement the five-year glidepath with seven-year and 10-year glidepaths for comparison.[74] The Audit also recommended the Company accelerate its forestry line clearing cycle so that the LVD system was on a four- or five-year cycle by 2028, which the Company has taken into account, planning to significantly ramp up its line clearing activity to a five-year cycle, although not as rapidly as recommended by the Audit. The increased forestry spending would lead to some adjustments in year-by-year capital investments but would not eliminate the need for capital investments. Mr. Kelly testified that the Company was also slowing its investment pace in open-wire secondary (OWS) conversions by approximately one half in response to Liberty's recommendation.[75]

Mr. Kelly next addressed the Audit's comments regarding Consumers' historical SAIDI performance, which concluded the Company had not improved its reliability over the past decade. He stated that Consumers tracks and reports all-weather SAIDI, a well-established industry standard metric. He also asserted that five-year rolling averages should be used for such comparisons to limit annual variability and to reduce the arbitrariness of which cut-off dates to use.[76] Mr. Kelly countered both of the Audit's findings that SAIDI trends were worse in 2022 than in 2014, and MNSC and Attorney

[73] 3 Tr 1394.
[74] 3 Tr 1394.
[75] 3 Tr 1395.
[76] 3 Tr 1396-97.

General claims that the Company's reliability performance had not improved relative to its peers,[77] asserting that the Reliability Roadmap's investments were projected to deliver SAIDI x-MEDs in the second quartile or better by 2029, or five years after investments began substantially ramping up. The Company maintained this goal of providing its customers with better than average reliability performance, and Mr. Kelly stated that Consumers has demonstrated clear improvement in delivering reliable service to its customers, having already closed approximately 40% of this gap in performance since the Reliability Roadmap's filing.[78]

Mr. Kelly testified that the Company projected improvement in reliability performance using a model that projects SAIDI, System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI) based on historical relationships between these reliability metrics and forestry line clearing spending, capital investment in the distribution system, and certain CAIDI improvements. The model considered future projected forestry line clearing spending, capital investment in key areas, and CAIDI improvements and, in return, the model projected SAIDI, SAIFI, and CAIDI.[79] While variances were expected in projections, Mr. Kelly stated that the Company had confidence in its modeling of the glidepath given a total net variance over the past five years of seven minutes.[80] He noted the Company's requested distribution capital investments and distribution O&M spending, as well as the robust line clearing plan, supported the planned glidepath to this improved SAIDI

[77] 3 Tr 1397-98.
[78] 3 Tr 1399.
[79] 3 Tr 1400.
[80] 3 Tr 1401.

performance for customers.[81] Mr. Kelly further testified that in some areas, the Company's investments and activities would drive a net reduction in SAIFI over the glidepath period, while other investments were necessary to prevent SAIFI from getting even worse.[82] He also stated that as the number of outages was reduced, crews would have fewer outages to respond to; this reduction in workload would allow crews to more quickly address outages that do occur which would produce CAIDI savings.[83]

Mr. Kelly explained that some investments identified in the Reliability Roadmap are intended to address asset health risk, assets that are in poor health and at heightened risk of failure in the near future, an issue that was most prominent when considering the HVD system, substations, and Metro infrastructure.[84] Mr. Kelly stated that while line clearing was an important part of how the Company was working to improve reliability, line clearing alone was not sufficient. He noted that systemwide line clearing benefits would take time to materialize even as the Company began shifting to a five-year clearing cycle, whereas capital investment in the distribution system had already begun delivering reliability benefits. The downward trend indicated that investments were well-targeted, and that they quickly delivered benefits, and should therefore work in conjunction with increases in forestry work.[85] The Company's investments in hardening the system would reduce the number of customer

[81] 3 Tr 1402.
[82] 3 Tr 1403.
[83] 3 Tr 1405.
[84] 3 Tr 1406.
[85] 3 Tr 1407.

interruptions and/or make the interruptions shorter, countering the impacts trees had on the system.[86]

While increased line clearing will eventually reach diminishing returns, or a point at which continued increases will not create benefits in a cost-effective way; with the revised line clearing plan, Mr. Kelly asserted that Consumers only needs to invest in the equivalent of 85 zonal health projects per year. This change in the equivalent number of zonal health projects resulted in an $80 million reduction in the capital that otherwise would have been requested by the Company.[87] Mr. Kelly averred that the Company would have been able to achieve the Reliability Roadmap goal of second quartile SAIDI a year earlier than originally outlined in 2028 had it not adjusted the capital plan in response to the Audit's recommendations.[88]

Mr. Kelly then testified regarding the alternatives the Company considered in developing the Reliability Roadmap and its investment plan. Mr. Kelly indicated that the Company first considered alternatives to the Reliability Roadmap as a whole and second considered alternatives to individual projects.[89] Mr. Kelly stated that based on the Liberty Audit recommendation, Consumers also modeled the results of slowing its pace of investment to reach the SAIDI target over seven or 10 years. According to him, these slower glidepaths would nearly eliminate the most beneficial reliability and resiliency programs for the LVD system.[90] These alternatives would reduce capital by approximately an additional $35 million a year for the seven-year glidepath and

---

[86] 3 Tr 1409.
[87] 3 Tr 1409-10.
[88] 3 Tr 1410.
[89] 3 Tr 1411.
[90] 3 Tr 1412.

approximately $50 million a year for the 10-year glidepath and would also result in Consumers having a less diverse portfolio of reliability investments.[91] Mr. Kelly stated that the slower glidepaths suggested by the Audit would leave the Company's performance lagging in the third quartile until well into the next decade, whereas customers would benefit from the Company's plan for more rapid improvement in reliability.[92]

Mr. Kelly testified that the Company is fundamentally committed to delivering reliable electric service to its customers as a core business principle, noting that both CUB and the Attorney General have assessed Michigan utilities as unreliable.[93] Therefore, Consumers must consider the reliability performance that it must deliver to meet the targets established through the Commission's PBR mechanism[94] Both the Commission and various stakeholders expect significantly improved reliability, which the Company stated could be achieved at the investment levels outlined in the Reliability Roadmap, but not at the reduced investment levels recommended by the Liberty Audit.[95]

Mr. Kelly testified that the Company used the Interruption Cost Estimate (ICE) Calculator tool developed by Lawrence Berkeley National Laboratory and Resource Innovations, and funded by the Energy Resilience Division of the U.S. Department of Energy's (DOE) Office of Electricity, which calculated that the Reliability Roadmap SAIDI projection would yield up to $6.1 billion worth of benefits in avoided outage

---

[91] 3 Tr 1412-13.
[92] 3 Tr 1413.
[93] 3 Tr 1413-1414.
[94] 3 Tr 1415.
[95] 3 Tr 1417.

costs.[96] For that reason, he stated the Company believed the investments and spending projected in the Reliability Roadmap represented the right mix of work to deliver improved reliability.[97]

Ms. Schiller discussed Staff's position on the Reliability Roadmap, testifying that on July 10, 2025, after this case was filed, and after receiving feedback and comments from participating utilities, including Consumers, the Commission issued an order approving Staff's proposed guidance with modifications for future DSPs.[98] The guidelines informed the Company that it may submit a revised DSP within a rate proceeding under two circumstances 1) significant misalignments between spend categories/allocations following changes in investment strategy; or 2) differences between the DSP and the rate case that the utility judges to be significant.

While Ms. Schiller believed the Company was following the best guidance it had at the time for documenting changes in its DSP investment strategy, she also noted that the refiled document did not align with the intent of the guidelines and Commission order. She further noted that the Commission provided additional context in its order by defining "significant" under Section VI as "including areas within a utility's DSP where strategies have changed, where spending levels and/or timing for investments have materially changed, and/or where whole new investment categories are included and discussed" and "foresees as being a rarity as opposed to the normal course."[99]

Ms. Schiller also observed that within the Company's exhibits and testimony in this case, many projects, programs, and subprograms changed names or were moved.

---

[96] 3 Tr 1417.
[97] 3 Tr 1418.
[98] 6 Tr 4291-4292.
[99] 6 Tr 4293.

These changes were not always documented and made Staff's comparison between the Reliability Roadmap and rate case documents difficult. In addition, because of the changes documented by Mr. Kelly, many capital costs changed between the 2023 DSP and the current case. While Ms. Schiller testified that Staff did not oppose the content of these changes necessarily, and she acknowledged that all plans and forecasts were subject to change, the recategorization of these changes between the 2023 DSP and the current rate case made these investments very difficult to track between the plan and rate case.[100]

Ms. Schiller testified that the Commission provided guidance regarding changes to the DSP. Specifically, she stated that the Commission noted several times in its order in Consumers' last rate case that "recategorizing or shifting of expenditures from one subprogram to another may lend confusion to the process of identifying historical costs and benefits as well as justifying projected expenditures" and that "simply relabeling or recategorizing capital expenditures from one program or tracking method to another does not provide sufficient evidence to demonstrate the reasonableness and prudence of costs nor the benefits of program expenditures."[101] The order directed the Company to be clear to changes and avoid any confusion when discussing historical and planned investments.

Given that DSPs discuss planned investments, there was no exception for alignment between the DSP and rate case categories.[102] Ms. Schiller noted the Commission disallowed several expenses on such reasoning in the Company's

[100] 6 Tr 4294.
[101] 6 Tr 4296.
[102] 6 Tr 4296.

previous rate case, and stated that: “the Commission expects to see additional detail in future electric rate cases regarding line items that have been recategorized, the past spending levels for those line items, how historical spending for any relabeled line items compares to proposed expenditures, and clarity on how these investments deliver value for the company’s customers.”[103] Because the new guidelines were approved after the Company submitted this rate case, Ms. Schiller indicated that Staff was not recommending any disallowances in this case due to misalignment between the Reliability Roadmap and the rate case.[104] However, she noted that Staff recommends the Commission recognize such and consider that any costs in future cases that were unable to be reconciled or tracked between the planning efforts and the rate case be disallowed.[105]

Ms. Schiller stated that the Company contested the Audit finding that it had not meaningfully improved its reliability over the past decade, arguing that SAIDI has improved in the three most recent years. The Company also claimed that a five-year average was most appropriate, as it would “limit annual variability.”[106] Ms. Schiller explained that the Company’s use of a rolling five-year average created the illusion of a declining trendline over the period 2014-2024. She testified that using a rolling average could obscure other trends and as such, the line lagged the current data. She stated Staff used the same data as the Company and ran a typical linear regression trendline to better demonstrate the movement of SAIDI performance in the past decade, using

[103] 6 Tr 4296.
[104] 6 Tr 4297.
[105] 6 Tr 4297.
[106] 6 Tr 4300.

the entirety of the data instead of a five-year average noting that there was a marked lack of reliability improvement.[107]

Ms. Schiller testified that the Company confirmed through discovery that the model it was using to project potential SAIDI improvements only considered the prior five years of historical data, and not the larger decade trend presented by the Audit, to create its five-year, seven-year, and ten-year improvement projections.[108] However, Staff found that these projected glidepaths did not meet the requirements set by the Commission order in Case No. U-21305 because the Company did not meaningfully examine an extended period to reach second quartile SAIDI performance, and there was no attempt by the Company to show how this extended period could contribute to cost effectiveness, affordability, or decreased rate impacts.[109] She noted that Staff also took issue with the Company's insistence that the Commission must allow recovery of investments to avoid penalties the Commission itself had set, noting that no "glidepath" shown on the Company's projections would result in a financial penalty.[110] She stated that removal of financial penalties or the acquisition of incentives may be a priority of Consumers, but that did not mean that recovery of related costs was inherently reasonable.[111]

Ms. Schiller recommended that the Commission and Consumers give more thought to these potential extended timelines for SAIDI improvements in the Company's next rate case, and recommended the Commission closely scrutinize the models the

---

[107] 6 Tr 4300-1; Exhibit S-19.1.
[108] 6 Tr 4302.
[109] 6 Tr 4302-4304. Case No. U-21305 addresses the Liberty Audit.
[110] 6 Tr 4306.
[111] 6 Tr 4306.

Company would use to project such investments and compare it to the Company's history appropriately. She stated that Staff also recommends the Commission not allow any spending in future rate cases that was based solely on avoiding financial penalties set by the Commission. Further, she testified that Staff recommends the Commission consider extending the historical data requirements currently presented in the guidelines from the July 10th order in U-20147 to ten years, as available, should the Commission choose to revise the guidelines.[112]

Mr. Fitzhenry testified on behalf of ABATE regarding Consumers' current electric service reliability and the Company's proposed distribution capital expenditures. Mr. Fitzhenry noted that the Company measures electric service reliability using several reliability metrics, most prominently SAIDI. Based on the Company's data from 2015-2024, SAIDI performance x-MEDs was 155 minutes in 2024, which was better than the projected 170 minutes. However, the Liberty Audit assessed the Company's historical SAIDI performance and concluded that reliability had not improved over the past decade, despite increases in total capital and O&M expenditures.[113]

Mr. Fitzhenry compared the Company's all-weather SAIDI and SAIDI x-MEDs to other investor-owned utilities in Michigan and states sharing a land border with Michigan (Ohio, Indiana, and Wisconsin) for the period 2020-2024. He noted the purpose of reducing the scope of the reliability comparison analysis to only include neighboring states was so the utilities included in the analysis shared a similar geographic region and were thus impacted by similar weather patterns.[114] He concluded that Consumers

[112] 6 Tr 4307.
[113] 6 Tr 3713-14.
[114] 6 Tr 3714.

ranked between 12 and 17, depending on the metric and year, with an average rank of about 15 out of 17. This put Consumers at or near the bottom in terms of reliability performance within its peer utilities over the last five years.[115]

Mr. Fitzhenry also summarized the number of customer minutes of power interruption (CMI) by outage cause for the last three years (2022-2024). He testified that most outages were caused by trees, including trees outside the ROW (52%), and the second leading cause of outages was the result of weather (26%). Meaning that only 22% of outages were the result of other causes such as equipment failures, car/pole accidents, unique incidents, etc.[116] Therefore, Mr. Fitzhenry asserted that if the Company intends to make any meaningful improvement to its future reliability metrics, then the primary focus should be on vegetation management as opposed to asset replacement since equipment failures only accounted for a small percentage of total outage minutes.[117]

Mr. Fitzhenry noted that the Company's distribution plant capital expenditure additions have increased from approximately $590 million in 2020 to $878 million in 2024, an increase of $287 million or 49% in five years. Meanwhile, he noted there had been no discernable trend in the Company's all-weather SAIDI metric over the same period. This means that the Company has not been able to reduce customer outage minutes, despite significant increases in the annual distribution capital expenditure levels.[118]

---

[115] 6 Tr 3714-15.
[116] 6 Tr 3716.
[117] 6 Tr 3716.
[118] 6 Tr 3717.

Mr. Fitzhenry concluded that the Company's position that its reliability was improving was based on a cherry-picked view of its data, selectively focusing on SAIDI x-MEDs, while ignoring the more critical all-weather SAIDI metric that reflects the actual experiences of its customers. While the Company claimed its SAIDI performance x-MEDs was improving, a broader comparison shows that it consistently ranks at the bottom of its peers. Although the Company's distribution plant additions increased by 49%—or $287 million—over the past five years, this increase in spending has not translated into any meaningful reliability gains for customers. Mr. Fitzhenry opined that the Company should be directing its investment to focus on the primary cause of outages, as opposed to focusing on capital investments to grow future returns.[119] As a result, Mr. Fitzhenry recommended that the Commission demand that the Company first demonstrate a clear link between its investments and quantifiable improvements in reliability before any further rate increases were considered and that the Commission reduce the Company's proposed distribution capital investments, as discussed below.[120]

CUB witness Bunch also noted that the revenue increase Consumers requests in this proceeding is not justified based on the need to improve system reliability, observing that in 2023, the average Consumers' customer was without power for 913 minutes, compared to the U.S. average of 342 minutes. According to Mr. Bunch, customers should not be required to pay increasingly higher rates for little or no improvement in reliability.[121]

---

[119] 6 Tr 3718.
[120] 6 Tr 3718-19.
[121] 6 Tr 4022.

On behalf of the CEO Mr. Tan testified that he found Consumers' reliability analysis reasonable, but he noted that looking at the Company's all-weather SAIDI and SAIDI x-MEDs the results show that Consumers ranks in the bottom quartile for reliability compared to its peers.[122] Mr. Tan also commended Consumers for the extensive regression analyses the Company contracted for as part of this rate case, and he recommended, in future regression analyses, that the Company focus on a narrower set of reliability metrics including SAIDI, SAIFI, and CAIDI, both all-weather and x-MEDs, as well as Customers Experiencing Long Interruption Duration (CELID) for at least five hours (CELID-5) and at least 24 hours (CELID-24).[123]

In rebuttal, Mr. Kelly testified that Consumers agrees with Staff on the need to present costs in the DSP in a way that is more easily tracked to costs in the rate case, and the Company will endeavor to provide costs in this way in its 2026 iteration of the Reliability Roadmap.[124]

In response to Staff's concerns about the Company's use of a rolling average in its reliability analysis, Mr. Kelly testified that Staff's approach, using linear regression over a decade, is flawed because it is highly dependent on the base year used in the regression. Mr. Kelly pointed out that Staff used 2014 as its starting point; however, that was a particularly good year for SAIDI performance, but using other years when SAIDI was higher would change the results. Mr. Kelly defended the Company's use of a rolling average, maintaining that it smooths out variability and eliminates an arbitrary start

---

[122] 4 Tr 3229.
[123] 4 Tr 3235-3237. In its initial brief, Consumers indicates that it agrees with Mr. Tan's recommendation. See, Consumers brief, p. 436.
[124] 3 Tr 1568.

date.[125] Further, Mr. Kelly opined that even if SAIDI were relatively flat over the analysis period, it would still indicate improvements in light of system deterioration and worsening weather.[126]

In response to Staff's concern that Consumers did not seriously evaluate alternative glidepaths, as recommended by the Liberty Audit, Mr. Kelly explained that the Company's reliability projection model forecasts achieving SAIDI in the second quartile in 2029, based on spending, and that Consumers used the same model to evaluate seven and 10-year glidepaths. Moreover, Staff did not indicate what more the Company could have done in its evaluation of alternatives.[127]

In its order in Consumers' previous rate case, Case No. U-21585, the Commission acknowledged statements made by Consumers and noted the Commission's full agreement with the Company that it appropriately used its Reliability Roadmap—not as evidence and argument that the Commission should grant approval of the Company's projected expenditures in the instant case simply because they are consistent with the Reliability Roadmap, but rather as part of the Company's evidence to support the reasonableness and prudence of its planned distribution expenditures, to show broader context, and to afford parties to the rate case the opportunity to examine and present evidence and arguments in response thereto. The Commission underscored that this was how distribution plans were supposed to be used in rate cases.[128]

---

[125] 3 Tr 1569.
[126] 3 Tr 1573.
[127] 3 Tr 1412, 1570.
[128] March 21, 2025 order in Case No. U-21585, p. 20.

The Commission also acknowledged the issues raised by intervenors, specifically highlighting the concern over the difference in increased spending for capital projects of 44% to improve reliability in that case while spending projections for the proven and cost-effective method of tree trimming remained relatively flat. The Commission found these spending projections to be incongruous and encouraged the Company to heed this noted concern.[129] The Commission also expressed concern with the disproportionate increase to capital projects over potentially more cost-effective O&M expenditures, as well as ongoing questions over whether certain cost categories had been appropriately classified as capital rather than O&M.[130]

Since the Commission issued its final order in Consumers' last rate case, the Commission has reviewed and adopted, in large part, the findings of the Liberty Audit. Although Consumers disagrees with certain aspects of the Audit, the Commission has found that the Company should evaluate longer reliability glidepaths and spending stating:

> The Commission agrees with the overall goal of reaching the median industry level for SAIDI performance but underscores that achieving that goal must be done in a cost-effective manner. The Commission is not yet convinced that a slower pace in spending in certain areas will result in delayed reliability goals, if the company appropriately considers alternative routes to achieve improved reliability. As noted in the comments, tradeoffs between capital and operations and maintenance (O&M) spending, including tree trimming, must be fully evaluated, and requests for rate recovery must include evidence of the analysis performed which supports the plans proposed by the company.[131]

[129] March 21, 2025 order in Case No. U-21585, pp. 20-21.
[130] March 21, 2025 order in Case No. U-21585, pp. 21-22.
[131] June 12, 2025 order in Case No. U-21305, p. 18.

Consistent with the Commission's directives, this PFD recognizes and endeavors to address the interplay between the Reliability Roadmap and the Liberty Audit throughout the distribution section of this PFD.

Mr. Kelly testified that the Company's electric distribution system is comprised of High Voltage Distribution (HVD), Low Voltage Distribution (LVD), and Metro systems. As shown in Exhibit A-12, Schedule B5.7, and discussed in detail below, the Company proposes to invest $1,529,914,000 in distribution system capital projects, and spend $300,994,000 in distribution system O&M in the test year, as well as $1,598,050,000 in capital projects in the bridge period.[132]

a. High Voltage and Metro Distribution

Mr. Kelly explained that Consumers' HVD system includes two primary areas—lines and substations. The Company's HVD lines area consists almost entirely of 46 kV lines (96% of the total HVD miles) and includes radial 138 kV and 69 kV lines (4% and <1% of the total HVD miles, respectively). The HVD system is also made up of approximately 180 substations that contain HVD assets, 4,600 miles of HVD lines, and 1,100 LVD substations. Mr. Kelly testified that the HVD system is considered the backbone infrastructure of the electric distribution system because it connects the electric transmission system to the Company's LVD system. The HVD system is largely a looped system capable of continuing service to customers despite the loss of any single component.[133]

[132] 3 Tr 1382.
[133] 3 Tr 1385.

The Metro system provides underground distribution service in the downtown areas of six cities in the Company's service territory: Battle Creek, Flint, Grand Rapids, Jackson, Kalamazoo, and Saginaw. The primary benefit of the Metro System is to address space limitations where numerous utilities (electric, gas, telecommunications, water, and sewer) must use limited Right-of-Way (ROW) in public streets and alleys, especially because high-rise buildings had greater utility needs than in lower density areas.[134] Staff, the Attorney General, and ABATE raised concerns about certain HVD and Metro spending projections and subprograms. These concerns are addressed below.

i. HVD Lines Reliability

Ms. Hayward provided an overview of the HVD Lines Reliability subprogram, which is designed to "to address deteriorated HVD line assets that have been assessed to be in poor health, mitigating and reducing the contribution of the Company's HVD lines to SAIDI and improving their resiliency."[135] Ms. Hayward explained that within HVD Lines Reliability, there are seven spend areas including line rebuilds, pole top rehabilitation and replacement, pole replacement, switch replacement, sensor installation, and ROW acquisition, noting that sensors and ROW acquisition investments were transferred to the program in this proceeding, as shown in Figure 12 at 3 Tr 1191.[136] As shown in Exhibit A-113, the Company forecasted capital expenditures for HVD Lines Reliability of $133,667,000 for the bridge period and $107,667,000 for the projected test year.

---

[134] 3 Tr 1384-1385.
[135] 3 Tr 1188.
[136] 3 Tr 1188-1189.

ABATE witness Fitzhenry recommended that spending for HVD Lines Reliability, (and for HVD Substations Reliability) be limited to 2024 levels, citing the findings of the Liberty Audit, which did not see a significant benefit to investing in the HVD system, given that most outage minutes and expected reliability improvements are related to the LVD system.[137]

After first commenting that Consumers' HVD system is in better shape overall than the Company's LVD system, further noting the downward trend of outages affecting the HVD system, Mr. Coppola objected to the significant increase in HVD Lines Reliability investments, opining that capital expenditures should be focused on the LVD system.[138] Mr. Coppola took specific issue with projected spending in three categories under HVD Lines Reliability: 1) line rebuilds; 2) pole top rehabilitation; and 3) pole replacements. In addition, as shown in Exhibit AG-14, p. 4, Mr. Coppola recommended disallowances totaling $15,218,000 for the Alden, Leslie, and Morrice HVD line rebuild projects that are currently in the scoping or engineering design phase.

Addressing line rebuilds, Mr. Coppola observed that Consumers proposes to rebuild 65.8 miles of HVD line in the test period, noting that on average, the Company has rebuilt 20 miles of line per year, with the highest number of rebuild miles of 40 occurring in 2023. Mr. Coppola testified that although the bridge period proposal to rebuild 13 miles of line was reasonable, Consumers' plan to rebuild 65 miles in the test period is unreasonable and unsupported by data.[139] Accordingly, based on Consumers'

[137] 6 Tr 3733, 3735.
[138] 3 Tr 2460-2461.
[139] 3 Tr 2461.

projected cost per mile, multiplied by 40 miles of HVD line rebuilds, Mr. Coppola calculated a reduction of $14,015,000 in the test year.[140]

For pole top rehabilitations, Mr. Coppola reported that the Company intends to rehabilitate 54.7 miles of pole tops in the bridge period, increasing to 116.1 miles in the test period. Noting that pole top rehabilitation miles have varied significantly year-to-year, he calculated that the average number of miles of pole top rehabilitations per year is 50.5. Mr. Coppola opined that the 130% increase in pole top rehabilitation miles in the test period, compared to the historical average, was excessive and unsupported. To arrive at a more reasonable investment level, he used the Company's projected cost per mile, multiplied by the 50-mile average, resulting in a reduction of $6,830,000.[141]

Turning to pole replacements, Mr. Coppola testified that Consumers has replaced approximately 442 HVD poles per year based on the recent historical average. The Company intends to replace 2,010 poles in the bridge period and 1,161 poles in the test year. Pointing to Ms. Hayward's testimony at 3 Tr 1202-1204, regarding the backlog of red-tagged poles requiring replacement, Mr. Coppola cited discovery responses from the Company regarding how the backlog occurred:

> In discovery, the Attorney General asked the Company to explain why it allowed a backlog of pole replacements to build and did not address the replacement of those poles timely in prior years. The response is not clear and mentions leveraging an undisclosed tactic and another tactic of combining replacement with pole top rehabilitations and rebuilds. It also mentions that the Company's previous tactics and methodology involved time-consuming efforts to obtain right-of-way permissions and work permits. In response to discovery, the Company also provided the build-up in the backlog from 2016 to 2027. This additional information shows that

[140] 3 Tr 2461.
[141] 3 Tr 2462.

the backlog predated the year 2016 with 1,353 to be replaced, which steadily increased the backlog to 2,250 poles by the end of 2024.[142]

From this information, Mr. Coppola concluded that Consumers has not been diligent in addressing the pole replacement backlog, and it now wants to accelerate replacements from 2025-2027, placing a substantial cost burden on ratepayers.[143]

To reduce these costs, Mr. Coppola suggested that instead of catching up on pole replacements over three years, the replacement period should be extended to five years. Consistent with this recommendation, Mr. Coppola calculated the backlog to be 1,300 poles to be replaced over three years (433 poles per year), which, if spread over five years, would result in a reduction of $6.304 million in the bridge period and $5.002 million in the test year for pole replacement.

Lastly, ABATE witness York testified that Consumers projects ROW acquisition costs of $12.667 million in the bridge period and $11 million in the test period, noting Ms. Hayward's testimony that the Company "*may* need to acquire new rights of way or expand existing ones" during the bridge and test periods. Ms. York testified that Consumers' projection is based on the most recent cost of an executed project, but the Company did not provide actual historical costs for ROW acquisition or sufficient detail regarding the ROW costs for the recent executed project. Accordingly, she recommended complete disallowance of all bridge and test period costs for ROW acquisition.[144]

In rebuttal, Ms. Hayward first responded to Mr. Coppola's characterization of the HVD system as being in better shape than the LVD system, pointing to her direct

[142] 3 Tr 2463-2464; Exhibit AG-12.
[143] 3 Tr 2464.
[144] 6 Tr 3702-3703.

testimony that although the HVD system's share of SAIDI minutes is small, it is nevertheless essential to invest in HVD "to maintain it as the backbone of the system."[145]

In response to Mr. Coppola's recommendation concerning HVD line rebuilds, Ms. Hayward explained that the precise number of miles of rebuilds per year is inexact, because miles are counted in the year the project is completed, which can make it appear that the number of miles fluctuates significantly. According to her:

> 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.[146]

Further, Ms. Hayward testified that the bridge period projection here "is informed by" the work proposed and approved in the Company's last rate case and that the test period projection is a continuation of that work. She added that because HVD line rebuilds tend to be ongoing year-over-year, Consumers relies on consistent funding "to keep projects on track and ensure they can actually be completed."[147]

For HVD pole top rehabilitation projects, Ms. Hayward explained that, like with line rebuilds, much of the year-to-year variation has to do with the fact that these

---

[145] 3 Tr 1355.
[146] 3 Tr 1356.
[147] 3 Tr 1356-1357.

projects extend over more than one year, but the miles are not recorded until the project is completed.[148]

Regarding pole replacements, Ms. Hayward testified that the planned investment in pole replacement is consistent with the recommendations in the Liberty Audit, adding that poles are red-tagged due to significant deterioration that poses a threat to safety and reliability if the poles are not replaced. Ms. Hayward explained that Consumers' past practice of replacing poles as part of larger projects may have contributed to the backlog, but this does not alter the fact that the poles now need to be replaced.[149]

Lastly, concerning the three HVD line rebuild projects that Mr. Coppola claimed were premature to be included in rates, Ms. Hayward disagreed, testifying that engineering design is underway and the construction timeline for all three projects is on schedule for 2026 or early 2027. Ms. Hayward emphasized that engineering design does not occur until after the project is approved "and is generally completed concurrently with procurement of easements, major equipment, or construction activities." [150] She stated that Mr. Coppola does not dispute the accuracy of the construction schedule for the three projects, noting further that these are multi-year projects that will not be completed until late 2027.[151]

In response to Mr. Fitzhenry's recommendation to limit investments in HVD reliability to 2024 levels, based on the findings of the Liberty Audit, Ms. Hayward first noted that the report was issued in September 2024, yet in its March 21, 2025 order in Case No. U-21585, the Commission nevertheless approved "a meaningful increase in

[148] 3 Tr 1357.
[149] 3 Tr 1358.
[150] 3 Tr 1363.
[151] 3 Tr 1364.

HVD reliability. In other words, the Commission has supported increased investment in HVD reliability despite Liberty's recommendation."[152] Ms. Hayward added that she provided substantial evidence on the reasonableness, prudence, and need for these HVD investments in her direct testimony.[153]

In response to Ms. York's recommended full disallowance of ROW procurement costs, Ms. Hayward first observed that even if Ms. York wanted to exclude some ROW costs, it would not be appropriate to exclude all costs, pointing to Exhibit A-130, page 2, line 9, which shows that the Company "has incurred millions of dollars in ROW costs in historical years,"[154] She also referenced Exhibit A-218, which provides historical (2020-2024) HVD Lines reliability ROW costs ranging from approximately $896,000 in 2024 to $2.106 million in 2020. Page 2 of that Exhibit provides a list of 41 HVD lines projects planned for the bridge and test periods, with projected ROW costs.

In briefing, Consumers relies on Ms. Hayward's direct and rebuttal testimony, reiterating that the disallowances recommended by the Attorney General and ABATE should be rejected.

The Attorney General reiterates Mr. Coppola's testimony and responds to Ms. Hayward's rebuttal regarding the fact that certain projects span multiple years. She asserts that: "[w]hile certain projects may have costs that span over more than one year, it is not clear what the impact is on the average cost per projects when dozens or hundreds of projects are being forecasted. In her rebuttal testimony, Hayward does not quantify the impact other than identifying a few projects that may have costs spanning

[152] 3 Tr 1368.
[153] 3 Tr 1368.
[154] 3 Tr 1367.

more than one year."[155] Concerning pole replacements, the Attorney General maintains that Consumers created the backlog of poles needing replacement but failed to justify the need for such an accelerated replacement program now.[156] The Attorney General does not specifically address the Company's rebuttal concerning the three HVD line rebuild projects that Mr. Coppola found to be premature.

ABATE repeats Ms. York's testimony in its initial brief, but it does not respond to the Company's rebuttal regarding the historical ROW acquisition costs contained in Exhibit A-130, and project-specific projections in Exhibit A-218. ABATE also continues to advocate for a general reduction in this program, and HVD Substations Reliability, based on the Liberty Audit's findings that distribution investment should be focused on the LVD system.[157]

The parties' reply briefs generally do not provide further argument. ABATE reasserts that the ROW costs projected by Consumers are speculative and out-of-line with historical costs.[158]

First, this PFD finds Consumers' suggestion, that the Commission considered and rejected the recommendations of the Liberty Audit in approving HVD investments in the Company's previous rate case, to be misplaced. Beyond the status of the proceedings (awaiting comments) the Audit findings are not discussed extensively in the final order in Case No. U-21585, except to highlight the Commission's concerns about "the disproportionate increase to capital projects over potentially more cost-effective

[155] Attorney General brief, p. 20.
[156] Attorney General brief, p. 19.
[157] ABATE brief, pp. 15-17.
[158] ABATE reply brief, p. 3.

O&M expenditures,"[159] a concern that persists in the instant case. That said, this PFD finds that limiting HVD spending in certain subprograms to historical amounts, as recommended by ABATE, should be rejected, noting that a similar proposal for a blanket reduction to HVD investments was also rejected in Consumers' previous rate case.[160]

Second, this PFD finds that ABATE's recommended full disallowance of ROW costs should also be rejected. Ms. Hayward's testimony made clear that the ROW spending category had been transferred to HVD Lines Reliability and that historical costs for the program were set forth in Exhibit A-130, with projected and historical costs provided in Exhibit A-218. Although an assessment of past deviations in projected ROW investment versus actual may have been helpful, especially given the significant increase in ROW expenditures projected here, such analysis was not undertaken by ABATE.

Turning to the Attorney General's recommended adjustments, this PFD finds that for HVD line rebuilds, Ms. Hayward's rebuttal regarding how rebuild miles are actually recorded is persuasive. As shown in Figure 21, at 3 Tr 1208, the difference in spending amounts between the bridge and test period is small, even if the number of miles of lines rebuilt appears significantly inflated. Accordingly, the Attorney General's disallowance should be rejected

As was the case with recording of line rebuilds, the same appears to be true for pole top rehabilitations, where bridge and test period spending are similar, even though

[159] March 21, 2025 order in Case No. U-21585, pp. 21-22.
[160] Order, p. 23.

the number of miles rehabilitated appears to double in the test year, again due to ongoing projects that are carried over from the bridge period, with all mileage recorded in the test year. That said, this PFD questions why the units for pole top rehabilitations is expressed in miles, rather than in the number of pole top assemblies rehabilitated or projected to be rehabilitated. Providing additional information on actual units (pole top assemblies) completed, rather than miles, could assist the parties in better evaluating past and projected spending for this category.

As for Consumers' proposed HVD pole replacement capital expenditures, this PFD agrees with the Attorney General that:

> While the Company has offered some explanation for why it allowed this backlog to grow over the last eight to nine plus years, the management and planning of this program was in its control and there is no justification for the persistent delay in addressing pole replacements. Whatever the supposed cause, the Company has not adequately explained why pole replacement activity needs to be accelerated to the levels it proposes now.[161]

Lastly, this PFD finds that although the Alden, Leslie, and Morrice HVD line rebuild projects at issue are in the engineering design phase, there is no evidence in this record to indicate that the project construction schedule may slip, or that the projects may be canceled.

Consistent with the foregoing, this PFD adopts the Attorney General's adjustment and recommends that the revenue requirement in this case for HVD Lines Reliability should reflect a disallowance of $6.304 million in the bridge period and $5.002 million in the test year for HVD pole replacement.

---

[161] Attorney General brief, 19.

ii. HVD Substations Reliability

Ms. Hayward testified that the HVD Substations Reliability subprogram "ensures the long-term safe and reliable operation of HVD substations, and ensures the ongoing asset health of HVD substations, with spending to make needed replacements of existing substation equipment."[162] She explained that projects in this subprogram are identified and prioritized based on asset health information and inspection results. Ms. Hayward stated that the investment categories within the HVD Substation Reliability subprogram include 1) circuit breaker and circuit switch replacements; 2) transformer bushing replacements; 3) switch replacements; and 4) other replacement programs for specific equipment such as transformer replacements and lightning arresters.[163] She provided Consumers' rationale for spending in each of these categories in Figure 26, at 3 Tr 1216.

Ms. Hayward explained that since Consumers' previous rate case, the Company has removed some work (specifically, projects intended to address issues identified by inspections) from the HVD Lines and Substations Rehabilitation subprogram and transferred it to the HVD Substations Reliability subprogram.[164] As shown in Exhibit A-115, the Company is projecting HVD Substations Reliability capital expenditures of $47,322,000 in the bridge period and $39,680,000 in the test year, and as shown in Figure 29, at 3 Tr 1223, Ms. Hayward provided the number of replacement units for each investment category, projected bridge and test year investment amounts, and projected customer outage minutes avoided. Ms. Hayward's Figure 30 and Figure 31 at

[162] 3 Tr 1214.
[163] 3 Tr 1215-1216.
[164] 3 Tr 1216.

3 Tr 1224, detail the historical investments in the HVD Substations Reliability subprogram.[165]

Ms. Hayward also provided a detailed review of the intersection of the Reliability Roadmap with the proposed investments in the HVD Substations Reliability subprogram, highlighting: 1) the Company's finding that 10% of HVD substations are high priority for repair or replacement, and an additional 21% show cause for moderate concern, indicating ongoing deterioration; 2) Consumers' inspection program and asset health model show where targeted investments in the HVD system should occur; and 3) while overall SAIDI minutes attributed to HVD substations is small, investment in these assets is necessary to avoid high-impact outages.[166]

Specifically addressing circuit breakers and switches, Ms. Hayward explained that these are critical components, and that many of them were installed in the 1950s and 60s and are obsolete or in poor health.[167] Ms. Hayward further explained the Company's approach to projecting investments in the various categories within the subprogram, opining that, given the variability of scope among the projects, a unit-cost type of analysis is not appropriate.[168]

Ms. Durfee testified that as of June 2025, Consumers had spent $7.321 million of the Company's projection for HVD Substations Reliability, as shown in Exhibit S-16.4.[169] She explained that while Staff agrees with the value of the HVD Substations Reliability subprogram, it nevertheless recommends adjustment of the projected spending

[165] Figure 31 includes investments that were made in the former HVD Lines and Substations Rehabilitation subprogram.
[166] 3 Tr 1217-1221.
[167] 3 Tr 1222.
[168] 3 Tr 1223-1225.
[169] 6 Tr 4417.

amounts, based on the limited actual spending to date.[170] To calculate Staff's adjustment, Ms. Durfee assumed linear monthly spending going forward resulting in $14,642,000 in total spending in 2025, a reduction of $18.580 million. Applying inflation of 2.40%, Staff calculated a reduction of $9.107 million for the first four months of 2026. And again, applying inflation to the 2026 amount, Staff calculated a reduction of $24,567,000 for the test year.[171]

Mr. Coppola took issue with expenditures for circuit breakers/switches and other replacements, observing that the projected unit cost for 63 circuit breakers in the bridge period was $27,292, whereas for the test period, Consumers projected a unit cost of $320,770 for 73 circuit breakers. He further observed that the three-year average historical unit cost for circuit breakers was $133,500 for an average of 17 circuit breaker replacements per year.[172]

Mr. Coppola testified that Ms. Hayward did not provide any explanation in her direct testimony regarding why the projected numbers of circuit breaker replacements increased from an average of 17 to 67 in the bridge period and 74 in the test year, nor did she explain why the unit cost of circuit breakers more than doubles in the bridge and test periods compared to the historical cost. Mr. Coppola stated that "[n]o specific anomalies or problems have been identified with the targeted replacements to justify this four-fold increase in replacement activity."[173]

---

[170] 6 Tr 4418.
[171] Id.
[172] 3 Tr 2465-2466. There appears to be several typographical errors in this part of Mr. Coppola's testimony. The unit cost for circuit breakers/switches for the bridge period is $318,063.
[173] 3 Tr 2466.

To arrive and what he deemed a more reasonable forecast, Mr. Coppola increased the historical replacement number of 17 to 40 circuit breakers and applied the inflation adjusted historical unit cost, resulting in a disallowance of $14,543,000 from the bridge period and $18,130,000 from the test year.[174]

Turning to the Other replacements spending category, Mr. Coppola observed that Consumers projects 169 units in the bridge period at a total cost of $22,277,000 and 83 units in the test year at a total cost of $12,758,000, noting that in the most recent historical period, total expenditures for this spending category ranged from $332,000 to $1.1 million. According to Mr. Coppola, Ms. Hayward again failed to explain the significant increase in spending for this category, adding that the Company cited Exhibit A-109 in discovery. Mr. Coppola stated that Exhibit A-109 lists several animal mitigation and DSCADA projects planned for the bridge and test periods, without any explanation or justification for the significant increase in projects or spending amounts.[175]

Calculating a more reasonable projection, Mr. Coppola doubled the historical maximum expenditure amount to $2.2 million for both the bridge and test periods, resulting in a reduction of $20,277,000 for the bridge period and $10,588,000 for the test year.[176]

In rebuttal to Staff, Ms. Hayward stated that many HVD projects, particularly substation projects, do not have consistent month-to-month spending amounts due to the need for system reconfiguration in order to deenergize certain portions of the system. According to her, “many types of HVD projects can only be undertaken during

[174] 3 Tr 2466-2467.
[175] 3 Tr 2467.
[176] 3 Tr 2467-2468.

certain parts of the year. This can be due to weather, electric load conditions, or other limitations that impact when system reconfigurations are needed," adding that due to the complexity of many substation projects, consistent spend from month to month is not expected.[177]

Explaining that although the Company disagrees with the amount of Staff's disallowance, Consumers did reevaluate its projected spending levels for the HVD Substations Reliability subprogram, "consistent with Ms. Durfee's approach to this sub-program of evaluating how much is likely to be invested[.]"[178] Noting that the Commission order in the previous rate case came only weeks before the summer began and further explaining that unseasonably warm weather occurred in the fall of 2025, which precluded taking substations off-line, Ms. Hayward stated that Consumers now projects bridge period spending of $22.230 million, a reduction of $10.992 million from the Company's original projection. She recommended that the Commission adopt this updated amount and reject any adjustment to test period spending.

Turning to the Attorney General's recommended adjustments for circuit breakers and switches, Ms. Hayward first referenced her rebuttal to Staff indicating that the Company had already conceded some of the bridge year expenditures. She further explained that Consumers' past investments in circuit breakers predated the development of the Reliability Roadmap in 2023, which included a detailed review of HVD substation health and determined that increased investment in certain components, like circuit breakers, was necessary.[179] She also pointed to her direct

[177] 3 Tr 1343.
[178] 3 Tr 1344.
[179] 3 Tr 1359; Exhibit A-129 Figure 109.

testimony wherein she explained the issues with circuit breakers including obsolescence, poor asset health, and scarcity of replacement parts. She opined that while Mr. Coppola claimed that the Company had provided insufficient detail, he did not the indicate level of detail that would be appropriate.[180] For Mr. Coppola's Other investment category disallowances, Ms. Hayward again pointed to the Reliability Roadmap and the need to address concerns about asset health.[181]

As noted above, Mr. Fitzhenry recommended limiting investments in this subprogram to 2024 actual amounts, updated for inflation, based on the Liberty Audit findings that capital investments should be focused on the LVD system.[182]

The parties' briefs rely on the testimony of their respective witnesses. While Staff acknowledges Consumers reduction in the bridge period, Staff states that it stands by its original disallowance.[183] The Attorney General reiterates that Ms. Hayward's direct testimony does not address the dramatic increase in spending for circuit breakers or for Other projects, asserting that it is the Company's burden to support its projected spending "and seven lines of testimony and a list of projects in an exhibit is not adequate support[.]"[184]

This PFD finds that the Attorney General's adjustments to the HVD Substations Reliability subprogram should be adopted.[185] This PFD agrees with the Attorney General that Consumers failed to provide sufficient support for the significant spending

---

[180] 3 Tr 1359.
[181] 3 Tr 1360.
[182] 6 Tr 3734-3735. As discussed above, Mr. Fitzhenry's recommendation for a blanket reduction, based on 2024 historical costs should be rejected.
[183] Staff brief, p. 19.
[184] Attorney General brief, pp. 23-24.
[185] It should be noted that this PFD finds that Staff's method for adjusting the Company's projection was reasonable; however, the Attorney General's recommendation was specific, and it overlapped with Staff's more general adjustment. As such, Staff's recommendation is rejected.

increases for circuit breakers and switches and Other replacements. While the Company cites the Reliability Roadmap and asset health assessments as justification for HVD Substation investments, as discussed above, the Reliability Roadmap should be considered in light of the Liberty Audit, and the Commission's findings thereon.

Moreover, this PFD generally agrees with ABATE that although some reliability investments are needed for the HVD system (noting in particular Consumers' concern that 10% of its HVD substations are high priority for repair or replacement) overall, capital and O&M investments should be focused on the LVD system. Accordingly, this PFD recommends disallowances of $34,820,000 in the bridge period and $28,718,000 in the test year for the HVD Substations Reliability subprogram as recommended by the Attorney General.

iii. Transformer Bank Replacements and Substation Rebuilds

Ms. Hayward presented the Company's Transformer Bank Replacements and Substation Rebuilds sub-program, testifying that the sub-program is dedicated to 1) the capital repair or replacement of HVD and SEC substation equipment (primarily large substation transformers ranging in size from 2 MVA to 100 MVA); and 2) rebuilds of entire substations. She stated that both types of work typically consist of large projects that take place over multiple years in stages, with costs incurred across multiple years before the project is completed.[186] Ms. Hayward stated that when the asset health of an entire substation or of a large transformer within a substation deteriorates, the Company replaces them to reduce the risk of assets failing and causing impacts to customer

[186] 3 Tr 1226-1227.

reliability. Replacing these assets proactively prevents long duration outages.[187] She further noted that the multi-year planning component of these large projects make it particularly important for the Company to have predictably and consistently approved cost recovery on a year-to-year basis.[188]

Ms. Hayward testified that the Reliability Roadmap states that the Company needs to replace an average of 12 transformers yearly between HVD and strategic customer substations to address transformers in poor asset health, and the Company planned work related to 14 transformers in the bridge period and three transformers in the test year.[189] She noted that because it can take more than two years to obtain a single transformer, and the Company also places orders for transformers ahead of time to ensure they will be available in the years beyond the current case to support the increased replacement levels described in the Reliability Roadmap.

Ms. Hayward testified that the Company planned to make “progress payments” in both the bridge period and test year for future deliveries of approximately 30 transformers.[190] She further testified that the Company was working on more transformer replacements in the bridge period than in the test year because it was doing more work on the Alma and Blackstone substation rebuild projects which would require more financial investment, materials and workforce in the test year than in the bridge

[187] 3 Tr 1227.
[188] 3 Tr 1228.
[189] 3 Tr 1229-30.
[190] 3 Tr 1230; Exhibit A-109.

year.[191] She stated that because of this, the Company would not do as many transformer replacement projects in the test year.[192]

Ms. Hayward noted that consistent with the Reliability Roadmap, the Company intends to complete approximately two to four HVD and strategic customer substation rebuilds per year. In the bridge period in this case, the Company is performing work on four different substation rebuild projects: North Belding, Buskirk Creek, Armory, and Royal Substations.[193] In the test year, the Company plans to perform work on five different substation rebuild projects: Buskirk Creek, Armory, Royal, Cement City, and Mecosta Substations.[194] She testified that full substation rebuilds are only done when there are multiple failing assets, where substation rebuild was found to be a more cost-effective option than replacing individual components. Ms. Hayward noted that the other option would be to attempt to run each HVD substation component to failure, which would result in more customer outages and increased costs for customers in the long run as equipment would have to be replaced on a demand basis.[195] She explained that transformer replacement projects were selected in a similar manner, with a similar alternative option.[196] Ms. Hayward testified that the Armory Substation (replacing Alma Substation) and Royal Substation (replacing Blackstone Substation) replacement projects were among the Company's 25 largest overall test year distribution projects, and the associated concept approvals were included in the Company's Part III filing

[191] 3 Tr 1230.
[192] 3 Tr 1231.
[193] 3 Tr 1231; Exhibit A-109.
[194] 3 Tr 1232; Exhibit A-109.
[195] 3 Tr 1232-33.
[196] 3 Tr 1233.

requirements, which showed additional details around how these projects were selected.[197]

Ms. Hayward stated that the Company projected Transformer Bank Replacements and Substation Rebuilds capital expenditures of $46,666,000 in the bridge period, and $37,667,000 in the test year.[198] She listed 13 projects for the bridge period and ten projects for the test year, which included spending $1,000,000 on ROW acquisition for new substation projects.[199] Ms. Hayward testified that the Company experienced recent procurement challenges related to the Armory (Alma) and Royal (Blackstone) rebuild projects, indicating a need to have this step completed earlier in the project timeline as to not delay the replacement of these substations. Procurement of ROW for projects beyond the test period was necessary to keep these future multi-year projects on track.[200] She further testified that the bridge period and test year spending amounts were determined for the HVD substation replacement projects investment category based on the projects identified for those periods.[201]

Staff witness Durfee testified that the Company's projected expenditures for the Transformer Bank Replacement and Substation Rebuilds sub-program were $35,332,000 in 2025; $11,333,000 for the four months ending 4/30/2026; and $37,667,000 in the test year. According to her, the Company spent $7,468,000 in the first 6 months of 2025.[202] Ms. Durfee noted that Staff agrees that the Transformer Bank Replacement and Substation Rebuilds subprogram is necessary to prevent long-term

---

[197] 3 Tr 1233.
[198] 3 Tr 1234; Exhibits A-109, A-110.
[199] 3 Tr 1234-35; Exhibits A-109, A-110.
[200] 3 Tr 1235.
[201] 3 Tr 1235; Exhibits A-109, A-110.
[202] 6 Tr 4418-19; Exhibit S-16.1.

outages and ensure the substations are ready to serve customers. However, given that the Company had only spent a fraction of what was needed to meet the projected spend in 2025, Staff recommended adjusting the forecasted expenditures.[203]

Ms. Durfee stated that assuming linear monthly spending, based on actual expenditures for the first six months of 2025, she calculated a total expenditure for 2025 of $14,936,000. Using this projection, Staff recommended a disallowance of $20,396,000 for 2025. Applying a 2.40% inflation factor for 2026, she projected expenditures of $5,093,000 for the four months ending 4/30/2026 and recommended a disallowance of $6,240,000 for that period. Again, applying a 2.40% inflation factor for 2027, she projected an expenditure of $15,417,000 for the test year and recommended a disallowance of $22,250,000.[204]

In rebuttal, Ms. Hayward noted that Ms. Durfee's recommended disallowance was based on reviewing the Company's year-to-date spending through June 2025 in the relevant sub-program; translating that spending into a percentage of the Company's filed projection for the 2025 calendar year; assuming that the average monthly spending for the first six months of 2025 would be carried forward into the future on a linear basis; and 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.[205]

Ms. Hayward explained that the Company faced limitations over the summer and into the early fall in its ability to take needed planned outages and many of the projects

---

[203] 6 Tr 4419.
[204] 6 Tr 4419.
[205] 3 Tr 1343.

in this sub-program had permitting requirements, which caused delays earlier this year. She stated that these factors combined resulted in year-to-date spending through June to be lower than projected; however, the Company continues to forecast that it will be able to catch up and achieve the full projected bridge period amount 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 was cooler later in the year. As a result, Ms. Hayward asserted that Ms. Durfee's recommended disallowances should not be adopted for the bridge period or the test year.[206]

As shown in Exhibit AG-14, p. 6, Mr. Coppola recommended the Commission remove $13,974,000 for the projected test year from the Company's forecasted capital expenditures for two Transformer Bank replacement projects (Alma and Blackstone) he found premature, given their current phase of development.[207]

In response to Mr. Coppola's testimony that the Alma and Blackstone substation rebuild projects were in the early phase of development and completion was uncertain, Ms. Hayward testified that the two projects are multi-year projects with property acquisition ongoing and capital expenditures already incurred.[208] She noted that both of these projects were included in the Company's last rate case in what was then called the HVD Lines and Substations Rehabilitation subprogram; 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, Ms. Hayward asserted that the

[206] 3 Tr 1346.
[207] 3 Tr 2468.
[208] 3 Tr 1361-62.

Commission should reject Mr. Coppola's proposed disallowances for these so-called "premature" projects.[209]

In its brief, the Company reiterates testimony on the subject before asserting that it continues to forecast it will catch up and achieve the full projected bridge period amount 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.[210] Based on its forecasted spending, the Company argues that Staff's recommended disallowance should not be adopted for the bridge period or test year.[211] The Company also argues that the Alma and Blackstone substation rebuild projects are multi-year projects with capital costs already being incurred.[212] Therefore, the Attorney General's recommended removal of two projects from this sub-program is inappropriate.[213]

In its brief, Staff recommends reducing transformer bank replacements and substation rebuilds capital expenditures by $48,886,000.[214] Staff reiterates that its recommendation is based on the Company-provided year-to-date spend in the sub-program being only a fraction of the projected spend for 2025 and a Staff determination that the unit cost of transformers should not include an increase.[215] Staff states that Ms.

---

[209] 3 Tr 1362.
[210] Consumers brief, pp. 18-20.
[211] Consumers brief, p. 20.
[212] Consumers brief, pp. 20-21.
[213] Consumers brief, pp. 20-21.
[214] Staff brief, p. 13.
[215] Staff brief, p. 15.

Hayward's rebuttal does not change these facts or make the disallowance less reasonable.[216] The Attorney General brief does not specifically address this topic.

After reviewing the record on the Transformer Bank Replacements and Substation Rebuilds sub-program, this PFD finds that Staff's adjustments should be adopted. The Company failed to adequately justify its projected expenditures to support its claim that it will catch up from its slow start in 2025, nor did it demonstrate that additional issues, like the permitting or planned outages problems that Consumers claims limited project execution earlier, will not occur going forward.

While this PFD recognizes that Staff's linear spending assumption may not be completely appropriate in all cases, in instances where the investment is discretionary, projected costs are already included in rates, and the actual year-to-date spend deviates significantly from the projection, Staff's approach for calculating the adjustment is reasonable. This PFD further recommends the Commission reject the Attorney General's recommendation to disallow recovery of costs in this subprogram. As Consumers points out, the costs for the Alma and Blackstone substation projects were included in the Company's last rate case, albeit as part of a different subprogram, and there is no indication in this record that these projects are not ongoing.

iv. Metro Rehabilitation

Ms. Haywood provided an overview of the Metro system which provides underground distribution services in the downtown areas of six cities in Consumers' service territory. According to her, "[t]he primary benefit of the Metro System is to address space limitations where numerous utilities (electric, gas, telecommunications,

[216] Staff brief, p. 19.

water, and sewer) must use limited right-of-way ("ROW") in public streets and alleys, especially because high-rise buildings have greater utility needs than in lower density areas."[217]

Ms. Hayward explained that the Metro Rehabilitation subprogram addresses underground assets in the Company's metro system that are at high risk of failure and that replacement is justified based on safety risks to the public, employees, and contractors or for reliability reasons. She testified that there are two investment areas in the subprogram: 1) crushed duct replacements; and 2) vault or manhole rehabilitation.[218] After discussing the need for these investments, Ms. Hayward described how the Metro Rehabilitation subprogram aligns with the Reliability Roadmap objectives for addressing asset health concerns.[219]

Ms. Hayward testified that specific planned projects in the Metro Rehabilitation subprogram are identified in Exhibit A-109, p. 7 for the bridge period, and A-110, p. 7 for the test year. As shown in Exhibit A-113, Consumers projects capital expenditures of $7,987,000 in the bridge period and $5,993,000 in the test year.[220]

Ms. Durfee testified that Staff agrees that investments in the Company's metro system will provide reliability benefits to customers and will help provide a safe work environment; however, Staff raised a concern that Consumers had only spent $1,430,000 of a projected $5,990,000 in the first six months of 2025. Accordingly, Staff recommended adjustments to the bridge and test period projected expenditures.[221]

---

[217] 3 Tr 1181-1182.
[218] 3 Tr 1264.
[219] 3 Tr 1265.
[220] 3 Tr 1267.
[221] 6 Tr 4420.

Based on the six months of actual spending, Ms. Durfee assumed that future spending would be linear through 2025, resulting in total spending of $2.860 million in 2025, a reduction of $3.130 million. Applying inflation for the first four months of 2026 and the test year, Ms. Durfee calculated disallowances of $1,022,000 for 1/1/2026-4/30/2026 and $3,041,000 for the test year.[222]

As shown in Exhibit AG-14, p. 7, Mr. Coppola recommended a test year disallowance of $3,600,000 for the Washington Avenue project, on grounds that the project was in the early planning stages and should not be included in rates at this time.

In rebuttal, Ms. Hayward disagreed with Staff's approach to adjusting bridge and test period capital expenditures, explaining that, in general, "[m]any 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."[223]

For the Metro Rehabilitation program specifically, Ms. Hayward cited Exhibit A-219, line 7, which shows that as of September 2025, the Company had spent $2,045,744 of an updated 2025 projection of $5.189 million. She explained that the types of projects undertaken for the Metro Rehabilitation subprogram "are primarily executed once frost has receded. Therefore, investments are frequently skewed towards the later part of the year," noting that the updated spending projection for 2025 is close to the Company's original projection.[224] Ms. Hayward concluded that because

[222] 6 Tr 4420-4421.
[223] 3 Tr 1343.
[224] 3 Tr 1347.

Staff's proposed disallowance for 2025 was no longer relevant, the disallowance for the remainder of the bridge period and test year should likewise be rejected.[225]

Turning to Mr. Coppola's recommended disallowance, Ms. Hayward explained that the Washington Avenue 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."[226]

The parties' briefing tracks the testimony of their respective witnesses.[227] Staff continues to recommend its disallowance totaling $7.193 million based on 2025 year-to-date spending, as discussed by Ms. Durfee.[228] The Attorney General does not specifically address her proposed adjustment.

This PFD agrees with Staff's recommendation to adjust bridge and test year costs for the Metro Rehabilitation program as set forth in Ms. Durfee's testimony. Although Consumers claims that because of the presence of frost, these projects "are primarily executed once frost has receded . . . [t]herefore Investments are frequently skewed towards the later part of the year," Consumers nevertheless does not explain why spending in the Metro Rehabilitation subprogram was higher, at $286,330 in February and $550,101 in March, than it was in any of the months from May through August of 2025, as shown in Exhibit A-219, line 7.[229] And while the Company forecasts substantial increased spending from October through December, it would seem that frost would also be an impediment to project execution in November and December.

---

[225] Id.
[226] 3 Tr 1364.
[227] See, Consumers brief, pp. 22-23.
[228] Staff brief, pp. 14, 15, 19.
[229] Consumers brief, 23.

Moreover, as discussed elsewhere in this section, this PFD agrees that Staff's assumption of linear spending is not unreasonable in circumstances where the investment is discretionary, costs are already included in rates, and the year-to-date spending deviates significantly from the Company's projection. Consistent with the above discussion, this PFD adopts Staff's proposed disallowances of $3.130 million in 2025, $1,022,000 for the first four months of 2026 and $3,041,000 for the test year.[230]

v. System Control Projects

Ms. Hayward presented the Company's System Control Projects subprogram, which consists of projects to improve management of the distribution system by improving operations of control centers, streamlining operations, and improving remote control capabilities to enhance safety and reliability. This work includes operating technology enhancements and operations center modifications. Operating technology enhancements improve functionality and operations of the: System Control Center (SCC), Distribution Control Center (DCC), and Work Management Centers (WMCs). These three groups are responsible for monitoring the system and ensuring a reliable power supply for all customers.[231] Ms. Hayward testified that improving monitoring and control capabilities on the distribution system helps streamline operations and reduces the impact of any single fault, reducing interruptions for customers. The technology enhancements and control room modifications will better enable employees to provide safe and reliable electricity.[232]

---

[230] Because Staff's adjustment overlaps with the disallowance proposed by the Attorney General, the Attorney General's recommendation is rejected.
[231] 3 Tr 1294.
[232] 3 Tr 1295.

In Case No. U-21585, the Company projected test year investment of $279,000 for this sub-program, and this amount was approved by the Commission. In the instant case, Consumers maintained projected investment levels at approximately the same amount. Ms. Hayward noted that spending in this sub-program was inherently variable on a year-over-year basis primarily because this sub-program consists of discrete one-time projects.[233] According to Ms. Hayward, test year spending in this subprogram was lower than the five-year historical average for two primary reasons. First, as the Company planned to transition to a Unified Control Center, less investment was needed in the existing facilities that would be replaced. Second, work that had historically been performed in the HVD Operations Projects investment category was being transitioned largely to the HVD Lines Reliability sub-program, reducing the total amount spent in System Control Projects.[234]

Ms. Durfee testified that Consumers' projected expenditures were: $279,000 in 2025; $93,000 for the four months ending 4/30/2026; and $219,000 for the test year. She noted that the Company spent $70,000 in the first six months of 2025.

Ms. Durfee testified that Staff agrees that the investments in the System Control Projects would benefit customers and better enable employees to provide safe and reliable electricity; however, given that the Company had only spent a fraction of what was needed to meet the projected spend in 2025, Staff recommended adjusting the projected expenditures.[235] Ms. Durfee stated that assuming linear monthly spend, the actual expenditures for the first six months of 2025 were projected to arrive at a total

[233] 3 Tr 1295.
[234] 3 Tr 1296.
[235] 6 Tr 4421-22; Exhibit S-16.1.

spend for 2025 of $140,000. Based on this projection, Ms. Durfee recommended a disallowance of $139,000 for 2025. Applying a 2.40% inflation factor for 2026, she projected an expenditure of $48,000 for the four months ending 4/30/2026 and recommended a disallowance of $45,000. Again applying a 2.40% inflation factor for 2027, she also projected an expenditure of $145,000 for the 12 months ending 4/30/2027 and recommended a disallowance of $74,000.[236]

Ms. Hayward disagreed with Staff's recommendation, stating that spending in the first half of 2025 may have been lower than projections would indicate, but the Company's projections, especially for 2026 and 2027, were still reasonable reflections of likely spending amounts. She acknowledged that the spending in this sub-program had been variable from year to year, and noted that Ms. Durfee did not look at actual spending as a proxy for what the Company could spend, but instead assumed a linear monthly spending level to project how much she believed the Company would actually spend in 2025 and then used 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.[237] Ms. Hayward stated that the Company projected to invest much less than in 2024, which indicated that the Company could invest at projected levels. As a result, Ms. Hayward stated that Ms. Durfee's proposed disallowance should be rejected.[238]

In its brief, the Company reiterates testimony and notes that it projected a test year investment of $279,000 for this sub-program, maintaining the investment levels

[236] 6 Tr 4422.
[237] 3 Tr 1348.
[238] 3 Tr 1348.

approved by the Commission in a previous case.[239] The Company notes that Staff agrees that the investments in the System Control Projects will benefit customers and better enable employees to provide safe and reliable electricity, but expressed concern regarding the Company's spending so far in 2025.[240] The Company reiterates that Staff's assumed linear monthly spending is an inappropriate methodology.[241] While acknowledging that its 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 spending in this sub-program has been somewhat variable from year-to-year, and the Company is projecting to spend less than its 2024 actuals.[242] Therefore, the Company asserts that Staff's recommended disallowance should be rejected.[243]

In its brief, Staff argues that the Commission should reduce the Company's projected distribution capital expenditures for its System Control projects by $258,000.[244] Staff reiterated that its disallowances were appropriate based on the Company-provided year-to-date spend in that subprogram being only a fraction of the projected spend for 2025.[245] According to Staff, Ms. Hayward's rebuttal does not change this fact or make the disallowance less reasonable.[246]

After reviewing the testimony and arguments provided by the parties on System Control Projects, this PFD finds that Staff's adjustments should be adopted. The

---

[239] Consumers brief, p. 24.
[240] Consumers brief, p. 24.
[241] Consumers brief, pp. 24-25.
[242] Consumers brief, p. 25.
[243] Consumers brief, p. 25.
[244] Staff brief, p. 15.
[245] Staff brief, p. 15.
[246] Staff brief, p. 19.

Company needs to provide more information on its spending plans – particularly in the case where a project is discretionary and where it does not appear to be on track with its projected spending. Accordingly, this PFD recommends the Commission adopt Staff's recommended disallowances of $139,000 for 2025, $45,000 for the first four months of 2026, and $74,000 for the test year.

vi. LVD Substations Demand Failures

Ms. Hayward explained that the LVD Substations Demand Failures subprogram supports emergent "capital repair or replacement of failed LVD substation equipment to restore customer service and maintain reliability of electrical service[,]" adding that the program includes regulators, reclosers, transformers and other substation equipment.[247] Ms. Hayward stated that the bridge and test period expenditures of $11.923 million and $8.961 million, respectively, were based on a five year average of component failures, as shown in Exhibit A-113 and Figure 66 at 3 Tr 1320.

Ms. Durfee testified that Staff agrees that the LVD Substations Demand Failures subprogram is essential to safety and reliability of substation operation; however, Staff disagreed with the unit price for transformers Consumers used in its cost projections. Ms. Durfee explained that while the Company projected a cost increase for transformers, historical data in Exhibit A-130, p. 2, shows that the cost of transformers has not always shown an increase, noting that the unit cost decreased from 2021 to 2022 and from 2023 to 2024. Thus, Ms. Durfee used the five-year average unit cost of $700,000 per transformer, multiplied by four transformer replacements, resulting in a

[247] 3 Tr 1318.

reduction of $580,000 for the test period, $435,000 for 2025, and $145,000 for the four months ending April 30, 2026.[248]

In rebuttal, Ms. Hayward pointed out that based on the historical costs of transformers, shown in Exhibit A-130, the five-year average unit cost is $742,000, not $700,000 as calculated by Ms. Durfee. Ms. Hayward added that in late 2024, the Company placed orders for transformers, after a competitive bid process, costing $812,000 per transformer. According to her, this demonstrates that Consumers' bridge and test period projections for the LVD Substation Demand Failure subprogram are accurate.[249]

Staff's brief affirms its proposed disallowance of $1.160 million in the bridge and test periods, reiterating that transformer costs have not shown a consistent upward trend. However, Staff does not address the Company's rebuttal that the five-year average cost of a transformer is $42,000 more than the amount calculated by Ms. Durfee.[250] Consumers' brief relies on Ms. Hayward's testimony, reiterating that Staff's calculation of the average cost of a transformer is understated and that recent data shows increasing costs for transformers.[251]

This PFD finds that Staff's adjustment, based on Ms. Durfee's calculation of the five-year average cost of a transformer, should be adopted. As Staff points out, the unit cost of a transformer varies considerably and is not showing a consistent upward trend. And it appears that Staff calculated its adjustment by adding the unit costs for transformers shown in columns c, f, i, l, and o in Exhibit A-130, p. 2, line 30, then

[248] 6 Tr 4423.
[249] 3 Tr 1349.
[250] Staff brief, 15, 17, 19.
[251] Consumers brief, 26.

dividing by 5, which results in a five-year average unit cost of $700,236. In contrast, Ms. Haywood testified that the same exhibit, page, and line number "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." Given the time constraints under MCL 460.6a, this PFD is unable to verify the Company's calculations, and Consumers does not explain the significant discrepancy in the exhibit. Accordingly, this PFD adopts Staff's recommended disallowances of $580,000 for the test period, $435,000 for 2025, and $145,000 for the four months ending April 30, 2026.

vii. Metro Demand Failures

Ms. Hayward explained the capital projects, activities, and other types of work facilitated by expenditures in the Metro Demand Failures sub-program.[252] She testified that this subprogram involves the replacement of failed cables, transformers, and civil infrastructure within the Company's Metro systems, with costs highly dependent on the type of asset that fails.[253] Consumers projected its needed investment level in this subprogram based on historical averages and trends. In this filing, spending in Metro Demand Failures was divided into three investment categories: 1) cable failure and replacement; 2) transformer failure and replacement; and 3) civil infrastructure failure and replacement.[254] Ms. Hayward stated that electrical assets in Metro vaults may fail due to age, deterioration, standing water, and runoff contaminants (e.g. salt). The most common electrical assets that fail are Metro transformers, primary cable, and secondary

[252] 3 Tr 1321.
[253] 3 Tr 1321.
[254] 3 Tr 1322.

cable.[255] She further noted that many factors contributed to deterioration of the cabling, equipment, and civil infrastructure in the Metro systems, including age of the system and public damage.

According to Ms. Hayward, Consumers commonly sees several specific problems caused by deteriorating electrical equipment including primary cable failures; transformer and other electrical equipment failures; and secondary and services failures. She also testified that the Company commonly experiences public damage related failures resulting from work performed in the ROW without notification to the MISS DIG system; improper directional boring techniques used by contractors performing work for other utilities in the ROW; and new business and redevelopment engineered plans, including parts of the ROW, with poor surveying and notification to the Company.[256]

Ms. Hayward asserted that work in this sub-program is essential to restoring interrupted electrical service to customers served by the metro underground system or to make immediate repairs to the civil infrastructure to protect the public.[257] She testified that the Company projects capital expenditures of $664,000 in the bridge period, and $350,000 in the test year.[258] Ms. Hayward stated that the Company's projected bridge period and test year spending were based on a continuation of recent spending levels since 2021, after the re-categorization of imminent failure work to the Metro Rehabilitation sub-program.[259] She further noted that average unit cost was not a good

[255] 3 Tr 1322.
[256] 3 Tr 1323.
[257] 3 Tr 1324.
[258] 3 Tr 1324; Exhibit A-113.
[259] 3 Tr 1324.

measure of spending to predict the cost of an individual project in this sub-program because of the variance in work required to address failures, which ranged from $4,500 to $60,000 per project. Additionally, the number of units completed each year was small, which inhibited reliable unit cost metrics.[260]

Ms. Durfee testified regarding Staff's assessment of the Metro Failures subprogram, noting that Staff agrees that investment in this category is necessary to restore electric service to customers on the Metro system. Ms. Durfee observed that the Company spent $9,000 in the first six months of 2025, which was a fraction of what was needed to meet the projected spend for that year. As a result, Ms. Durfee stated that Staff recommended adjusting projected expenditures.[261]

Ms. Durfee explained the adjusted projected expenditures calculation which assumed a linear monthly spend based on actual expenditures for the first six months of 2025. Based on this projection, Ms. Durfee testified that Staff recommended a disallowance of $529,000 for 2025, a disallowance of $111,000 for the four months ending 4/30/2026, and a disallowance of $331,000 for the test year.[262]

In her rebuttal, Ms. Hayward testified that the Metro Demand Failures subprogram is based on emergent needs and heavily based on historical actuals, which provided a good proxy of what will likely be needed in the near future. Ms. Hayward asserted that the historical average, encompassing five years of data, was 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 as Ms. Durfee did to calculate Staff's proposed

---

[260] 3 Tr 1325.
[261] 6 Tr 4424.
[262] 6 Tr 4424.

disallowances. As a result, she asserted that the Company's projections for the test year and bridge year, which were closely aligned with the five-year average, should be approved by the Commission, instead of the much lower amount recommended by Ms. Durfee.[263]

In its brief, the Company repeats that the Metro Demand Failures sub-program is aimed at addressing emergent issues within the Metro system and specifically handles unexpected failures in the Metro system, involving the replacement of failed cables, transformers, and civil infrastructure. The Company projects its investment needs in this sub-program based on historical averages and trends.[264] The Company rejects Staff's recommended disallowances and asserts that Staff's methodology is inappropriate and fails to recognize how these expenditures actually occur – as emergent needs.[265] The Company asserts that projected Demand Failures investments are usually heavily based on historical actuals, which provide a good proxy of what will likely be needed in the future. The Company's test year projection is closely aligned with the five-year average; therefore, it argues projected spending levels should be approved by the Commission.[266]

In its brief, Staff reiterates its recommendation for a disallowance based on the Company provided year-to-date spend being only a fraction of the projected spend for 2025.[267] Staff responds to the Company's rebuttal, arguing that the Commission should approve Staff's disallowance because the Company's year-to-date spend in 2025 does

---

[263] 3 Tr 1350.
[264] Company brief, p. 27.
[265] Company brief, p. 28.
[266] Company brief, pp. 28-29.
[267] Staff brief, p. 15.

not support the Company's projected spending, and Ms. Hayward's rebuttal does not change this fact or make the disallowance less reasonable.[268]

The Company and Staff reply briefs do not offer additional information on this issue.

After reviewing the testimony and arguments provided by the parties on the Metro Demand Failures sub-program, this PFD finds Staff's recommended disallowances should be rejected. As discussed above, while an assumption of linear spending may be reasonable for discretionary projects or programs, for the Metro Demand Failures subprogram, which addresses emergent needs and unexpected failures, an assumption of linear spending is inappropriate. Moreover, as discussed below, demand failures capital programs are included in the Company's distribution deferral mechanism, in the event that over- or underspending occurs. Therefore, this PFD recommends adoption of the Company's projection for Metro Demand Failures.

viii. LVD Substations Rehabilitation

Ms. Hayward described the LVD Substations Rehabilitation subprogram as consisting of repairs and replacements of substation equipment that has been assessed to be at imminent risk of failure, along with projects designed to replace obsolete equipment such as reclosers, breakers, fuses, and regulators, and to address code violations.[269] Ms. Hayward presented Figure 40 at 3 Tr 1249, which provides a list of various inspections performed as well as inspection frequencies.

[268] Staff brief, pp. 17,19.
[269] 3 Tr 1247-1248.

Ms. Hayward explained that the investment categories included in LVD Substations Rehabilitation are: 1) Allis Chalmers transformer replacements; and 2) equipment replacement and regulatory-related projects. With respect to the first category, Ms. Hayward testified:

> Allis Chalmers mid-20th century vintage substation power transformers were produced with a design deficiency associated with the top clamping structure of the transformer windings. The key purpose of the clamping structure is to prevent winding movement. This deficiency results in an inherent weakness of the transformer to withstand the forces accompanying certain magnitude low side faults. Winding movement typically results in electrical shorts and arcing, which lead to excessive heating, creation of combustible gasses, and eventual failure of the transformer.[270]

In addition, she stated that Consumers will have 37 of these Allis Chalmers transformers at its LVD substations, noting that from 2014-2018, 28% of transformer failures were from this vintage and manufacturer. Since 2018, the Company has not experienced any additional failures due to increased monitoring and replacement. Ms. Haywood reported that since 2017, Consumers has replaced between 3 and 19 Allis Chalmers transformers per year.[271]

For the equipment replacement and regulatory-related project investment category, Ms. Haywood explained that Consumers is not planning any end-of-life (EOL) rebuilds in the test year, but will be addressing regulatory-related projects for working space to bring substations into compliance with NESC Rule 125, section A.[272] Ms. Haywood reported that when the Company was upgrading telecommunications equipment it discovered that some of the substations were out of compliance with the

---

[270] 3 Tr 1250.
[271] 3 Tr 1251.
[272] Id.

NESC Rule and has been addressing these issues, with the intention of completing all compliance upgrades by 2028, with 24 of 66 capital projects remaining to be addressed.[273]

Turning to the obsolete equipment category, Ms. Haywood explained that when certain types of equipment and replacement parts are no longer available, and inventory levels are decreasing, Consumers classifies the parts or equipment as obsolete and replacements (which may require substation modifications) are installed. Ms. Haywood listed several projects that span multiple years, as shown in Exhibits A-108, p. 5 and A-110, p. 5.[274]

Overall, Consumers is projecting LVD Substations Rehabilitation capital expenditures of $40,895,000 in the bridge period, and $31,147,000 in the test year, as shown in Exhibit A-113.

Mr. Coppola testified that it appears that Consumers plans to replace all 37 remaining Allis Chalmers transformers by the end of the test year, noting that from 2022-2024, the Company replaced an average of four transformers per year. "Therefore, the 26 units planned to be replaced in the bridge period and the additional 18 units in the projected test year represent a significant increase in in activity."[275] Noting that Consumers has addressed the issues with these transformers for decades, Mr. Coppola objected to the significantly accelerated pace of replacement proposed in the instant case and instead recommended that the replacement be spaced over the

[273] 3 Tr 1251-1252.
[274] 3 Tr 1252.
[275] 3 Tr 2454-2455.

next four years, with nine replacements in the bridge period, eight in the test year, with the remaining 14 transformers replaced over the next two years.[276]

Based on the Company's forecasted unit costs, Mr. Coppola calculated a reduction of $14,689,000 in the bridge period for the replacement of nine units and a reduction of $8,082,000 in the test year for the replacement of eight units.[277]

For the equipment replacement and regulatory category, Mr. Coppola again observed that Consumers is projecting a significant increase in the number of units and unit cost of projects in the bridge and test periods. He explained that the Company intends to complete 26 units at a cost of $708,846 per unit in the bridge period, and an additional 13 projects at a unit cost of $1,276,846 in the test period. Mr. Coppola calculated that in the past three years, Consumers implemented about 10 projects per year, at a unit cost of $511.340. According to him, Consumers provided no explanation or justification for the significant increase in unit cost in the bridge and test periods.[278]

To arrive at what he considered a more reasonable amount, Mr. Coppola used the three-year historical average adjusted for inflation, resulting in disallowances of $11,592,000 in the bridge period (for 13 projects) and $11,209,000 in the test year (for 10 projects).[279]

In rebuttal, Ms. Hayward reiterated that the Allis Chalmers transformers have a history of problems and the Company's intention in the instant case is to finally resolve those problems, emphasizing that "[t]he Company should not drag the process out

---

[276] 3 Tr 2455.
[277] Id.
[278] 3 Tr 2456.
[279] 3 Tr 2456-2457.

further, and the Commission should approve the Company's projection."[280] Ms. Hayward added that the spending on transformer replacements was approved in Consumers' last rate case, and investment is well underway. Thus, if the Commission decides to slow the pace of investment in transformer replacements, it should only do so in the test year.[281]

Similarly, for equipment replacement and regulatory, Ms. Hayward explained that a unit-cost approach is not appropriate for this category, given the diversity of project types that Company plans to undertake, and the fact that several projects span multiple years, which affects the ability to accurately calculate unit costs. Citing Exhibits A-109 and A-110, she pointed out the variability of project costs, ranging from $149,000 to $1.485 million in the bridge period and $330,000 to $3.381 million in the test year. She added that Mr. Coppola offered no reason to limit the number of projects to the three-year average, and that bridge period spending is in line with the Commission's approval in Case No. U-21585. As such, any limits on spending should apply to the test period only.[282]

Consumers' and the Attorney General's briefs reiterate the testimony of their respective witnesses. In response to Ms. Hayward's rebuttal indicating that the replacement of the Allis Chalmers transformers should not be delayed, the Attorney General posits that the Company has not evaluated the alternative to complete the transformer replacement project over four years, rather than two, and provide rate relief

[280] 3 Tr 1351.
[281] 3 Tr 1352.
[282] 3 Tr 1352.

to customers.[283] In response to Consumers' contention that bridge period spending on transformer replacement is predicated on the Commission's approvals in the Company's previous rate case, the Attorney General argues that it is not clear from the order in Case No. U-21585 whether the Commission specifically addressed transformer replacement. She adds:

> The timing issue is a result of the Company's choice to file rate cases within a few months after an order is issued in the previous case. Unfortunately, that creates a situation where capital spending is forecasted for the same project over two rate cases before they have been completed with capital spending overlapping from case to case. That should not be used as the basis for denying the Attorney General's proposal. The Commission should approve a spending level that will allow replacements to occur over a longer period as proposed by the Attorney General.[284]

This PFD finds that for the Allis Chalmers transformer replacements, the Attorney General's adjustments should be adopted. As the Attorney General points out, Consumers has managed the issues with these transformers adequately, as demonstrated by the fact that none of the transformers has failed since 2018 due to increased monitoring. While this PFD recognizes that these faulty units will all need to be replaced eventually, in light of the very large rate increase Consumers is requesting in the instant case, a more measured approach to transformer replacement is reasonable. Therefore, this PFD adopts the Attorney General's recommended disallowances of $14,689,000 in the bridge period and $8,082,000 in the test year for transformer replacements.

---

[283] Attorney General brief, 38.
[284] Attorney General brief, 38.

For the equipment replacement and regulatory category, this PFD agrees with Consumers that the variability in cost of the specific projects that the Company undertakes in this category does not lend itself to a unit cost type of analysis, as was performed by the Attorney General. Although some of the projects proposed could potentially be delayed, the record as a whole does not support a disallowance. As such, the Attorney General's recommended adjustments to this category are rejected.

ix. LVD Substations Capacity

According to Ms. Hayward:

> The LVD Substations Capacity sub-program ensures the long-term safe and reliable operation of the Company's electric distribution LVD substations. The necessary capital expenditures include investments to install new substations or substation equipment, and to upgrade existing substations or substation equipment to ensure customer electric loads are served within the operating capacity of the installed substation equipment (i.e. transformers, fuses, reclosers, regulators, and switches). The LVD Substations Capacity investments are divided into two categories: new substations and existing substation capacity increases.[285]

Ms. Hayward explained that beginning in 2024, HVD line work and ROW procurement for new and existing substations were transferred to the LVD Substation Capacity subprogram from the HVD Lines and Substation Capacity subprogram in order to better align investment categorization and project cost tracking.[286]

Next, Ms. Hayward discussed alternative approaches explored as part of each project including: 1) transferring load to an adjacent substation; 2) upgrading equipment or lines to provide additional capacity; 3) building a new LVD substation to share load; and 4) connecting to a different HVD source. She further explained that LVD Substation

[285] 3 Tr 1288.
[286] Id.

Capacity projects are selected in response to peak load conditions through monitoring and analysis of DSCADA information, with substations exhibiting higher overloads prioritized. Ms. Hayward stated that the Company has listed projects for the bridge period in Exhibit A-109, p. 10, and for the test period in Exhibit A-110, p. 10.[287] As shown in Exhibit A-113, Consumers is projecting capital expenditures of $29,656,000 in the bridge period and $22,251,000 in the test year. As set forth in Figure 56 at 3 Tr 1292, the Company forecasts 4 new substations and 19 projects at existing substations in the bridge period, and 11 new substations and 4 projects at existing substations in the test year.

Mr. Coppola stated that the Company's forecast of four new substations in the bridge period was in line with historical trends; however, its forecast of 11 new substations in the test year was significantly more than the number of substations built in the past. From 2021 through 2024 (excluding 2023, when no new substations were built) Mr. Coppola calculated that Consumers has completed an average of five new substations per year. He opined that Consumers has not provided sufficient evidence regarding why the number of new substations needs to double in the test period.[288]

To adjust the Company's projected investment to a more reasonable level, Mr. Coppola used the historical average of five substations per year at Consumers' projected cost of $1,845,727, resulting in a disallowance of $11,074,000 in the test year for new LVD substations.[289]

---

[287] 3 Tr 1289-1290.
[288] 3 Tr 2457-2458.
[289] Id.

For investments in existing substations, Mr. Coppola again noted that the Company completed an average of nine projects annually, and he questioned why Consumers more than doubled that number in bridge period in this case. According to him, when asked in discovery about the problems being addressed by the bridge period projects, the Company responded by referencing Ms. Hayward's direct testimony and a list of substations experiencing overload conditions. Mr. Coppola opined that Ms. Hayward's testimony "provides only general statements about addressing customers increasing load demands with no specifics."[290] He added that the list of planned projects "does not identify the level of overload experienced and why these are priority projects that need to be completed in the bridge period."[291]

To arrive at a more reasonable investment level for existing substations, Mr. Coppola assumed 12 projects in the 16-month bridge period at a unit cost of $656,000, which, when adjusted for inflation, results in a bridge period disallowance of $16,420,000.

In rebuttal, Ms. Hayward disagreed with Mr. Coppola, pointing to her direct testimony and reiterating that the LVD Substation Capacity projects are 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."[292]

The parties' briefs rely on the testimony. Consumers emphasizes that the number of new substations and substation expansions "is dependent on pockets of local

---

[290] 3 Tr 2459.
[291] Id.
[292] 3 Tr 1353.

load growth, which is why the number can vary from year to year."[293] Consumers points to Exhibits A-109, p. 10 and A-110, p. 10 to demonstrate the need for the projects.

This PFD finds that the Company's justification for these projects in the bridge and test periods is sorely lacking. Ms. Hayward's direct testimony is general, at best, and Exhibits A-109 and A-110 only provide: 1) a list of the projects; 2) the investment category (new substation or increased capacity); and 3) the location of the project; and the number of customers served by each project. Nowhere in these exhibits is there any information about whether the substations at issue are currently overloaded, and if not, when they are projected to be overloaded. Nor did the Company provide any reasons for why load growth in parts of Consumers' service territory is so extensive that the number of new substations and capacity expansion projects more than doubles in the bridge or test year.

Therefore, this PFD recommends a disallowance of $16,420,000 for the bridge period and $11,074,000 for the projected test year from the Company's forecasted capital expenditures for the LVD Substations Capacity subprogram.

x. HVD Strategic Customers New Business

Ms. Hayward testified that the New Business program generally includes the capital investments necessary to connect new industrial, commercial, and residential customers to the Company's system. Discussing the HVD Strategic New Business subprogram specifically, Ms. Hayward explained:

> The HVD Strategic Customers New Business sub-program consists of the capital costs to meet the new business needs of large C&I customers that are too energy intensive to be served by the area LVD system, addressing

[293] Consumers brief, p. 33.

> both existing customers and potential new customers to locate a new facility in Michigan. Typical investments for this program include dedicated substations and interconnections of dedicated substations to the HVD system with poles, conductors, and metering to connect new C&I customers.[294]

Ms. Hayward testified that Consumers plans projects and develops investments for this program on the basis of customer commitments and projects with a high probability of moving forward, and that costs are net of any contributions made by customers. She noted that the timeline from a completed customer agreement to final interconnection can vary from six months to two years or more.[295]

Ms. Hayward described how projects are initiated by specific customers and the general process for developing cost projections and scheduling work. Ms. Hayward testified that Consumers projects $90,045,000 in the bridge period for six projects, and $43,860,000 in the test year for four projects in the HVD Strategic Customers New Business subprogram.[296] Historical spending in this subprogram has ranged from $4.038 million in 2020 to almost $58 million in 2024, with a five-year average amount of $19.5 million.[297]

Ms. Hayward noted that the projects listed in Exhibit A-109 are all fully committed; however, one project, a new dedicated substation, for which Consumers had a contract, was canceled in April of 2025. Ms. Hayward explained that:

> Because a contract existed and because expenditures had been approved by the Commission, the Company has already made some expenditures in the bridge period, and the Company is seeking recovery of these expenditures that were made in good faith. Pursuant to that termination and language in the customer's contract with the Company, the customer

---

[294] 3 Tr 1296.
[295] 3 Tr 1297.
[296] 3 Tr 1297-1298; Exhibits A-109, p. 11 and A-110, p. 11.
[297] 3 Tr 1303, Figure 59.

> is required to reimburse the Company for costs incurred for the project. Specifically, the customer is required to pay the Company the entire cost for work performed, materials not salvaged, and all reasonable cancellation expenses incurred to provide service, without interest, less payment made by the customer. If and when the Company recovers these costs from the customer, that money will be credited to this sub-program and netted back out of rate base.[298]

In addition to this canceled project, Ms. Hayward reported that there is funding included for certain high-probability projects where Consumers is in active negotiations with the expectation that the Company will have to make investments in the bridge and test periods to ensure that the customers' needs are met. She noted that Consumers is working in conjunction with the Michigan Economic Development Corporation (MEDC) and other economic development groups to accommodate these prospective large industrial customers.[299]

In Exhibit AG-14, p. 3, Mr. Coppola highlighted two bridge period projects that had been canceled in lines 2 ($4.340 million) and 6 ($22.965 million), as well as $7.349 million for "high-probability" projects. Mr. Coppola stated that the costs for the canceled projects should be disallowed, as well as the costs for the high probability projects, which he considered placeholder amounts.

In the test year, as shown on page 9 of Exhibit AG-14, line 5, another HVD substation project for $20,619,000 was listed as canceled, and there was an additional $6.470 million in high probability projects. Mr. Coppola recommended that these amounts be removed as well.

---

[298] 3 Tr 1299: Exhibit A-109, p. 11, line 2.
[299] 3 Tr 1299-1300; Exhibit A-109, p. 11, line 7.

Mr. Coppola raised three specific concerns with respect to the HVD Strategic Customers New Business subprogram, pointing out that Consumers already incurred $11.6 million on at least one project that was canceled and possibly additional amounts on a second canceled project. First, according to him, the Company is purchasing equipment and beginning design work on projects before the customer has signed the contract. He described this as "a very risky undertaking," the costs of which should not be assumed by other customers.

Second, Mr. Coppola explained that even if a customer enters a contract and commences operations, there is no guarantee that the customer may not close down or move to another state, leaving the Company with potentially millions of dollars in stranded assets, noting that Consumers does not require a customer contribution under its Large Economic Development Rate (LEDR). Lastly, Mr. Coppola stated:

> [R]egarding the accounting of costs incurred on cancelled projects, the response to DR AG-CE-0479 stated that the Company billed the former customer for a portion of the costs incurred for the cancelled project and retained the remainder in work in process pending resolution of salvage activities. This accounting treatment is not appropriate. Once a project has been cancelled, the costs should be removed from rate base and accounted separately below the line. If some of the facilities, equipment, or materials is later reused on utility projects than those amounts should be charged to future projects costs and rate base at that time.[300]

On behalf of ABATE, Ms. York also recommended that costs of $4.340 million associated with the canceled contract in the bridge period be removed from rate base, rather than credited back to customers once the Company has recovered some portion of the costs.[301]

---

[300] 3 Tr 2472.
[301] 6 Tr 3702.

In rebuttal, Ms. Hayward testified that "[a]lthough 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."[302] She explained that even if the contract is later canceled, "the investments were still reasonable and prudent at the time they were made."[303] Citing the two canceled substation projects shown in Exhibit AG-14, p. 3, with costs totaling $27,305,000, Ms. Hayward testified that $16.652 million had already been spent on these projects, meaning that the maximum disallowance should be $10.653 million.[304] For the test year, however, she agreed with Mr. Coppola that the $20.619 million for a canceled substation should be removed.

Turning to the high probability projects, Ms. Hayward disagreed with the Attorney General, citing the order in Case No. U-21585 wherein the Commission agreed with the Company that it was reasonable and prudent to obtain certain critical inventory to allow for execution of high probability projects when they arise.[305] In addition, she pointed to a discovery response that indicated that two contracts have been signed since Consumers filed its case, and costs for these projects make up a portion of the high probability project spending. Thus, she recommended that the Attorney General's removal of the amounts for these projects in the bridge and test periods should be rejected.[306]

---

[302] 3 Tr 1361.
[303] Id.
[304] 3 Tr 1362.
[305] Id.
[306] 3 Tr 1361, 1363.

Consumers' brief reiterates Ms. Hayward's testimony, emphasizing the benefits of the subprogram in terms of general economics (job development, tax revenues) as well as specific benefits to Consumers' customers because new load allows costs to be spread over a larger customer base. Consumers reiterates that in its order in Case No. U-21585, pp. 41-42, the Commission found that it was reasonable to procure inventory such that high-probability projects can be executed when they arise. Consumers also restates its concurrence that for the test year, $20.619 million for a substation that was canceled should be removed.

In its reply brief, Consumers contests the Attorney General's request for an accounting policy to remove all canceled projects from rate base, asserting the Company's obligation to serve, as well as claiming that "[t]he Commission has regularly determined that having a signed contract with the customer results in the associated investments being reasonable and prudent."[307]

The Attorney General relies on Mr. Coppola's testimony, reiterating that all costs for canceled projects should be removed, along with costs for high probability projects that are essentially placeholders. She argues that customers should not be required to pay for the return on investment, depreciation, and other costs for projects that may not go into service before the end of the test year, noting that if the projects are completed, costs may be included in the Company's next rate case.[308] The Attorney General also rejected the Company's partial adjustment of $10,653,000 in the bridge period for two

[307] Consumers reply, p. 2.
[308] Attorney General brief, p. 26.

canceled substations, stating that "[t]he recommended partial disallowance is not adequate for the cancelled projects."[309]

Turning to the high probability projects in the bridge and test periods, while the Attorney General acknowledges the Commission's order approving the procurement of certain inventory for the timely execution of such projects, she contends that Consumers did not provide any detail in testimony or exhibits on the items the Company planned to acquire. She further acknowledges the Company's claim that contracts have been signed for two of the high probability projects; however, Consumers did not provide evidence regarding the amount of capital costs for these contracts in discovery or rebuttal. As such, the Attorney General maintains that Consumers requests are unsupported.[310]

The Attorney General's reply brief addresses the Company's disagreement with her recommendation to remove spending related to unknown high probability projects because they are placeholders.[311] The Attorney General disagrees with the Company's interpretation of the Commission's order in Case No. U-21585, arguing that the Commission limited its decision indicating "that this decision is not to be construed as a green light for the blanket stockpiling of equipment and associated expenditures in future rate cases[.]" The Attorney General again recommends the Commission adopt her recommendation to disallow recovery of speculative costs.[312]

This PFD agrees with the Attorney General and ABATE that costs for canceled projects and unspecified "high probability" projects should be disallowed in both the

[309] Attorney General brief, p. 27.
[310] Attorney General brief, pp. 27-28
[311] Attorney General reply brief, p. 7.
[312] Attorney General reply brief, p. 8.

bridge and test periods. While the Commission apparently did approve costs associated with one canceled project in Consumers' last rate case, the Commission was persuaded by the Company's recitation of the number of inquiries and RFPs that it had received from large customers, and it found that the substation would be built.

Consumers argues that "[t]he Commission has regularly determined that having a signed contract with the customer results in the associated investments being reasonable and prudent."[313] This claim, however, is presented without support, and is beside the point in any event. Notably, the Commission did not review the Company's contracts (one of which is now breached, apparently) with any customer to assess whether the terms and conditions of those contracts were reasonable, prudent, and sufficiently protective of the Company and other ratepayers in the event the project did not go forward. That said, any decision regarding contract terms, including requiring upfront payment or penalties for breach, lies squarely with Consumers' management and not the Commission.

While Consumers is apparently in the process of collecting from at least one customer, it requests that already incurred costs be included in rates and netted from the proceeds it obtains through collection. This PFD agrees with the Attorney General and ABATE that the most reasonable approach is to remove the costs of canceled projects from rate base, under the assumption that the Company will recoup some of the investment from the customer and repurpose the remaining investment in equipment for other projects, the costs of which can later be included in rate base.

---

[313] Consumers reply, p. 2.

Lastly, for “high probability” projects, this PFD agrees with the Attorney General that despite the Company’s claim that it has now signed two contracts, Consumers did not provide sufficient information on what specific expenditures the Company expects to make in the bridge or test periods for these contracts. Moreover, if these projects are completed, the Company can recover reasonable and prudent costs in its next rate case.

Consistent with the foregoing discussion, this PFD finds that $4.340 million and $22.965 million for two canceled projects, as well as $7.349 million for unspecified projects should be removed from the bridge period. For the test year, this PFD finds that $20,619,000 for the project that was listed as canceled, and the additional $6.470 million in high probability projects, should also be disallowed.

xi. HVD Lines and Substations Capacity

Citing Mr. Kelly’s testimony, Ms. Hayward reiterated that the purpose of the capacity program is to ensure that Consumers can serve peak demand load, explaining that the HVD Lines and Substations Capacity subprogram is intended to: 1) ensure capacity on the HVD system consistent with HVD planning criteria; 2) accommodate new HVD connections; 3) improve operability of the system through upgrades; 4) coordination with transmission infrastructure additions; and 5) assist ROW acquisition for new projects and to bring existing ROWs to current standards.[314] As shown in Exhibit A-116, Consumers projects bridge period capital expenditures of $40,913,000, and test year expenditures of $29,447,000.

[314] 3 Tr 1277.

Mr. Coppola recommended that test year investment for two projects, the Linden 46 kV project ($5.1 million) and the Wealthy Street substation project ($3.070 million) should be disallowed, on grounds that the projects are too premature to be included in rates, as highlighted in Exhibit AG-14, p. 8.[315]

Ms. Hayward countered that the design for the Linden project will be complete in the first quarter of 2026, allowing a year after design completion to execute the project. For the Wealthy Street project, Ms. Hayward stated that design is expected to be completed by the first quarter of 2027, and that project costs included here are for long lead time materials.[316]

In briefing, the parties rely on their respective witnesses' testimony; the Attorney General does not specifically address these projects or the Company's rebuttal in her brief.

This PFD finds that the Attorney General's disallowances should be rejected. The PFD agrees that the proposed test year spending is likely to occur for the acquisition of equipment for the Wealthy Street project and that the Linden 46 kV line rebuild will be completed before the end of the test year.

xii. Metro Asset Relocation

Ms. Hayward testified that the Metro Asset Relocation subprogram addresses internal and external requests to relocate or modify structures such as manhole chimneys and castings due to road grade changes, that are not related to new business requests. Ms. Hayward explained that asset relocation requests may be on a demand

[315] 3 Tr 2469.
[316] 3 Tr 1264.

basis, or they may be planned and coordinated with local authorities, or with other Consumers' departments.[317] Noting that the Company seeks reimbursement of projects on a case-by-case basis, Ms. Hayward provided examples of two recent externally-requested relocation projects, and described Consumers' planning process for metro asset relocations.[318]

Ms. Hayward sponsored Exhibit A-109 and A-110, which list projects planned for the bridge period and test period, respectively. As set forth in Exhibit A-113, Consumers projects capital expenditures of $16,094,000 in the bridge period and $20,405,000 in the test year for Metro Asset Relocation.[319]

As shown in Exhibit AG-14, page 13, the Attorney General highlighted two Metro Relocation projects, Kalamazoo Ave Civil and Kalamazoo Ave Electric, that Mr. Coppola determined to be too premature to be included in rates at this time.

In rebuttal, Ms. Hayward testified that as shown in Exhibit AG-14, engineering and design work are well underway for the project, that "is tied to the well-publicized Kalamazoo Avenue two-way street conversion project," linking to a community projects page for the City of Kalamazoo.[320]

The Attorney General's briefing does not specifically address Ms. Hayward's rebuttal, beyond a general discussion of projects contained in Exhibit AG-14 that are in early phases of development.[321]

---

[317] 3 Tr 1330.
[318] 3 Tr 1330-1332.
[319] 3 Tr 1333.
[320] 3 Tr 1365.
[321] See, Attorney General brief, 25-26.

A review of the webpage cited by Ms. Hayward titled "Streets for All: Kalamazoo Ave (2026-2027)" indicates that the project is a full reconstruction of the street "that replaces aging underground utilities" among other improvements. According to the website, the project was expected to begin in 2025, but it was delayed until the spring of 2026 to allow for grant finalization.[322] As of the date the webpage was accessed (1/17/2025), there were no additional updates or indications that the project will be further delayed. And according to Exhibit AG-14, p. 10, design work for the projects began in Q3 of 2025 and is scheduled to end in Q1 of 2026, leaving sufficient time for project execution before the end of the test year.

Consistent with the foregoing discussion, this PFD finds that the Attorney General's disallowances for the Kalamazoo Metro Relocation projects should be rejected.

b. Low Voltage Distribution

Mr. Kelly testified that Consumers' LVD system is comprised of more than 111,304 total miles of lines, made up of approximately 51,736 miles of primary overhead, 9,885 miles of primary underground, 31,209 miles of secondary overhead, and 18,474 miles of secondary underground.[13] The LVD system consists of 13 different primary voltages between 2.4 kV and 24.9 kV (grounded-wye and delta).[14] LVD primary voltage is then further stepped down at the distribution pole-top or padmount transformer to a secondary voltage, serving businesses and residences at voltages between 120 Volts and 480 Volts.[15]

---

[322] See, https://www.kalamazoocity.org/Community/Projects/Streets-for-All/Streets-for-All-Kalamazoo-Ave-2026-2027

According to Mr. Kelly, More than 2,000 LVD circuits serve the Company's 1.9 million electric customers, where a circuit was defined as a combination of electrical devices and hardware that are connected and emanate from an LVD substation to deliver electrical energy to customers, operating at a defined nominal voltage.[16] The LVD system was expansive and subject to the greatest threat from common outage causes like trees, lightning, unexpected load increases, and third-party damage. The LVD system is largely a radial system, not capable of continuing service to customers during outages.[17]

Although the Company's testimony and brief discuss numerous programs and subprograms in the LVD category, this PFD only addresses LVD programs, subprograms, spending categories, or projects where costs are in dispute. The sub-programs under LVD include LVD Lines New Business (including LVD Lines and Transformers), LVD Lines Demand Failures (including LVD Lines Failures, LVD Substation Failures, and LVD Metering Failures), LVD Asset Relocations (including LVD Lines Relocation), and LVD Reliability (including LVD Lines, LVD Substations, LVD Repetitive Outages, LVD Substation Rehabilitation, LVD Lines Rehabilitation, and Resiliency).[323] The Company also has LVD subprograms related to Capacity (including LVD Lines, LVD Substations, LVD New Business, and Conservation Voltage Reduction (CVR)) – all of which will be discussed separately below.

As detailed, *infra*, the Attorney General proposes adjustments to the LVD Lines New Business; Staff proposes presentation of additional information regarding breakdown of costs for LVD Line Demand Failures in the Company's next rate case;

---

[323] 3 Tr 1893-1994.

Staff, the Attorney General, and ABATE propose adjustments to the Company's LVD Asset Relocations sub-program; and Staff, the Attorney General, ABATE, and MNSC propose adjustments to the LVD Reliability sub-program.

i. LVD Lines New Business

Consumers' New Business Program includes the capital costs of connecting customers to the Company's distribution grid. LVD Lines New Business includes the overhead or underground distribution extensions required to complete new service connections for residential and C&I customers.

Ms. Partlan testified that projects are initiated by customers, and the projected spending will allow the Company to provide a new service installation to every customer who requests it.[324] Consumers projected capital expenditures of $168.047 million in the 16-month bridge period and $130.2 million in the test year for LVD Lines New Business sub-program.[325] Ms. Partlan explained that the expenditures for LVD Lines New Business are based on historic growth and other projections, including those from the Home Builders Association of Michigan (HBAM).[326]

Mr. Coppola testified that his evaluation of the historical number of new service lines recently installed and recent economic trends demonstrates that the Company's forecasted units of 12,211 for the bridge period and 9,252 for the projected test year were reasonable. He, however, found that the unit cost forecasted to be "excessive relative [to] the average cost during the most recent historical year."[327] Mr. Coppola

[324] 3 Tr 1895.
[325] 3 Tr 1896.
[326] 3 Tr 1897-1898.

based his assessment on the $12,971 cost per unit in 2024, which was lower than in the previous two years.[328]

Citing lack of confidence in the Company's explanation for the methodology it used to arrive at cost per unit for the bridge period and test year, Mr. Coppola determined that it "is reasonable to assume that the unit cost reductions achieve in 2024 will continue into the projected test year with appropriate future inflation adjustments."[329] Thus, for the 16-month bridge period, Mr. Coppola used the 2024 unit cost ($12,971), applied an inflation rate of 2.9% to arrive at a forecasted unit cost ($13,347), and multiplied this cost by 12,211 units forecasted by the Company to arrive at $162.980 million for the bridge period.[330]

Similarly for the test year, Mr. Coppola applied an inflation rate of 2.4% to the 2024 unit cost ($12,971) and multiplied that number by 9,252 units forecasted by the Company to arrive at $126.447 million for the test year. This resulted in a proposed disallowance of $5.067 million for capital expenditures for the bridge period and a reduction of $3.753 million for the projected test year.[331] Mr. Coppola also expressed concern that the Company's contractor costs for this sub-program are significantly higher than in-house costs and recommended the Company's next rate case include a plan for how it will achieve further cost reductions including how contractor costs can be reduced or, in the alternative, the Company should bring more work in-house.[332]

---

[327] 3 Tr 2423.
[328] 3 Tr 2423.
[329] 3 Tr 2424.
[330] 3 Tr 2424.
[331] 3 Tr 2424.
[332] 3 Tr 2425-2026.

Staff witness Boutet recounted Commission decisions in Consumers' most recent electric rate case, Case No. U-21585, and concluded that the Company complied with the Commission's request for an analysis of line extension costs between external contractors and internal workforce for the LVD Lines New Business program.[333]

In rebuttal to Mr. Coppola, Ms. Partlan asserted that the Company's forecasted number of new service connections is reasonable. She took issue with Mr. Coppola's use of a single year of historical data in his methodology to propose a disallowance -- a year when the Company was able to achieve a lower per unit cost. She noted that this methodology deviates from the three-year historic average unit costs methodology he use for other costs analyses he does in this case.[334]

Additionally, while Ms. Partlan expressed that the Company does not oppose studying the issue of the difference in costs between contracted work and in-house work, she testified that the "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 construction customers connected in a timely manner if Company employees are engaged in other critical projects, such as reliability work."[335]

In its initial brief, citing the direct and rebuttal testimony of Ms. Partlan, the Company characterizes Mr. Coppola's analysis as an "overly-simplistic recommended reduction in projected expenditures."[336] The Company argues that Mr. Coppola's proposed disallowances, and the bases therefore, are unreasonable because: 1) it is

---

[333] 6 Tr 4365, citing Figure 7 of Company witness Partlan's direct testimony at 3 Tr 1902, which sets forth number of Company units versus number of contractor units and Company unit cost versus contractor unit cost.
[334] 3 Tr 2046-2047
[335] 3 Tr 2047.
[336] Consumers brief, p. 40.

unreasonable to assume that the Company will be able to maintain the unit cost reduction that it achieved in 2024, especially in light of the proposed tariff change that will increase the number of customers selecting underground service, which will increase costs; 2) the Company has experienced increased unit costs because of increases in average service length; and 3) Mr. Coppola's methodology is inconsistent with his proposal to use three-year averages to project unit costs in other parts of the case.[337]

The Company also noted that had the Attorney General utilized the three-year historical average unit cost, as she did for other projects in this case, it would have resulted in a unit cost of $13,705 per unit in the bridge period and $14,033 per unit in the projected test year, which are higher than Mr. Coppola's proposed per unit costs of $13,347 in the bridge period and $13,667 in the projected test year.[338]

In her initial brief, the Attorney General did not address the Company's objection to the use of a single year methodology in determining projected unit cost, nor did she respond to the Company's criticism of the Attorney General's deviation from the use of a three-year historical average for all other matters in this case – both of which were addressed in the rebuttal testimony of Ms. Partlan.[339] The Attorney General's reply brief was silent on these issues as well and, thus, did not provide a reply or argument in opposition to these matters or the Company's criticisms, which were addressed in the Company's initial brief.

---

[337] Consumers brief, p. 40; 3 Tr 1899-1902, 2046-2047.
[338] Consumers brief, p. 40.
[339] See 3 Tr 2046-2047.

There is, therefore, no record evidence or supporting argument by the Attorney General refuting the Company's testimony and arguments, including the basis for Attorney General's deviation from the use of a three-year historical average for other matters in this case to one-year for this particular issue.

It is worth noting that the Company's rebuttal testimony and argument in briefing demonstrate that the use of a three-year historical average would have resulted in a $13,762 per unit cost for the bridge period and $14,073 per unit cost for the projected test year.[340] The outcome of the use of a three-year historical average, thus, results in bridge period and test year costs that are very close to those proposed by the Company in this case. This PFD, therefore, finds that the evidence on the record, including the Attorney General's failure to refute or otherwise address the Company's rebuttal and arguments made in initial brief, demonstrates that the Attorney General's proposed disallowances for the bridge period and projected test year for the Company's LVD lines new business sub-program should be rejected.

Further, while the Company did not express an objection to the Attorney General's interest in obtaining information regarding the differences in contractor costs versus in-house costs for this subprogram in a future rate case, Mr. Boutet's testimony appears to demonstrate that the Company complied with this Commission requirement.

The Attorney General's briefing did not address these issues concerning use of and need for contracted workers. She also did not address Staff's position that the Company appears to have already complied with this request based on the

[340] These numbers are not articulated in this case, but are a calculation made by the ALJ based on information provided by the parties.

Commission's order in Case No. U-21585. Because the Attorney General's testimony and briefs provided no evidentiary detail regarding the cost differences that were of concern to her and further provided no response to the Company's explanation, this PFD also finds that there is a lack of evidence to support the Attorney General's request for a study in the Company's next rate case to justify the use of the contract versus in-house workers and that this request should also be rejected.

Lastly, this PFD notes that Mr. Kelly and Mr. Daly testified in support of deferred accounting authorization for the LVD Lines New Business sub-program, among others.[341] As Mr. Kelly explained, "the largest factors influencing expenditures in [this] program[] are externally driven."[342] Deferred accounting for New Business, Demand Failures, and Asset Relocations has been authorized as recently as the Company's last electric rate case, and Consumers has requested that it be allowed to continue to defer the revenue requirement for any capital spending for this program above what is included in rates.[343] These deferrals are reconciled in the Company's next rate case, thereby protecting customers if underspending occurs.

Consistent with the above discussion, this PFD recommends that the Commission approve the proposed bridge period and projected test year LVD Lines New Business capital costs presented by the Company in this case.

ii. LVD Lines Demand Failures

The Company's Demand Failures subprogram includes the capital costs associated with responding to day-to-day equipment failures and performing storm

[341] 3 Tr 1470.
[342] 3 Tr 1470.
[343] 3 Tr 1470.

restoration work. This subprogram does not include projects planned in advance and is meant for quick response(s) to system interruptions. LVD Lines Demand Failures includes two investment categories – Service Restoration Orders and Security Assessment Inspection Orders. Ms. Partlan testified that Service Restoration Orders are performed on an emergent basis to restore customers who are without power for various reasons (i.e. after storms or equipment failures), and Security Assessment Inspection Orders involve fixing issues identified in the Company's visual line inspections.[344] Consumers' projected capital expenditures of $186.059 million in the 16-month bridge period and $128.350 million in the test year for LVD Lines Demand Failures subprogram, and are based on the Company's expected completion of 37,500 orders in the bridge period and 26,000 order in the projected test year.[345]

Like LVD New Business, Mr. Kelly requests continued deferred accounting treatment for this subprogram, as one that has non-discretionary expenditures outside of the Company's control, with the same stipulations approved by the Commission in Case No. U-21585.[346]

Although there were no objections to the proposed expenditure amounts, Staff witness Schiller, addressing the Security Assessment Inspection Orders component of this subprogram, recommended the Company provide a breakdown of inspection costs and provide support for the Company's capitalization of these costs rather than classifying them as O&M.[347]

---

[344] 3 Tr 1904.
[345] 3 Tr 1910-1911; Exhibit A-113 (MPK-3).
[346] 3 Tr 1470.
[347] 6 Tr 4289-4290.

Ms. Schiller explained that LVD line inspections are visual inspections, occur over the entire LVD system annually, involve the use of internal and contracted labor for inspections, and have been viewed by the Company as components of engineering and supervisions of the construction work under the FERC Uniform System of Accounts (USOA).[348] She noted that the Company considers the inspection activity as classified under the USOA as "Engineering and supervision" which "includes the pay and expense of engineers, surveyors, draftsmen, inspectors, superintendents and their assistants applicable to the construction work," and, thus, classified those costs as capital rather than O&M.[349]

Ms. Schiller testified that Staff does not believe that the inspections have been properly interpreted under Section 3, subsection 11 and, instead, are better classified under Operating Expense Instructions, Section 2 of the USOA which includes, "[i]nspecting, testing, and reporting on condition of plant specifically to determine the need for repairs, replacements, rearrangements, and changes and inspecting and testing the adequacy of repairs which have been made."[350] She also noted that Ms. Partlan cited a 2015 Electric Power Research Institute (EPRI) report in her explanation of this subprogram which identifies those practices as systems maintenance.[351]

Although Staff did not recommend a capital disallowance and O&M credit based on its assessment of the erroneous classification, Ms. Schiller did recommend:

---

[348] 6 Tr 4289-4290; citing Electric Plant Instructions, Section 3, subsection 11 of the FERC USOA, adopted by the Commission in Case No. U-14811.
[349] 6 Tr 4289-4290.
[350] 6 Tr 4290.
[351] 6 TR 4290, citing to Partlan direct testimony 3 Tr 1906 and EPRI 2015 technical report *Distribution Grid Resiliency: Overhead Structures*, https://www.epri.com/research/products/000000003002006780, pages 9-13.

> [that the] Commission direct the Company to: 1) provide a thorough breakdown of inspection costs applied across all capital programs/subprograms, 2) support why these costs are appropriately classified as capital instead of O&M with reference(s) to accounting guidance, and 3) amend the classification of these expenditures in the Company's next rate case, where necessary, based on the analysis. The Company should explain why section 2 under the Operating Expense Instructions of USOA is not appropriate and why section 3 under the Electric Plant Instructions of USOA is appropriate 3 under recommendation #2 above.[352]

In its initial brief, the Company disagrees with Staff's concerns over the categorization of Security Assessment Inspection Orders as capital instead of O&M, but agreed that, in its next rate case, it will "review its capitalization policies around line inspections and security assessment work on the distribution system and propose any necessary changes."[353]

Staff's brief presented a little bit of a wrinkle in this issue. Ms. Schiller only discussed Staff's concern over the classification of the Security Assessment Inspection Orders component of the Company's LVD Lines Demand Failures subprogram in her testimony, her recommendation was broader and included a request that the Company "provide a thorough breakdown of inspection costs ***applied across <u>all</u> capital programs/subprograms***." Staff acknowledges that Consumers may have misunderstood its recommendation when the Company agreed to review its capitalization policies surrounding "line inspections and security assessment work."[354] Consumers did not address this in its reply brief.

Because the Company's proposed investment in the LVD Lines Demand Failures sub-program was not opposed by any party in this case, this PFD recommends

[352] 6 Tr 4290-4291.
[353] Consumers' brief, pp. 41-42; 3 Tr 2044-2045.
[354] Staff's brief, pp 170-171.

approval of the Company's proposed investment. Concerning Staff's recommendation, in testimony and as expanded in briefing, this PFD notes that the Commission recently addressed this issue in a DTE Electric rate case, wherein the Commission observed that:

> [C]oncerns raised in this proceeding regarding capitalization policies are not limited to DTE Electric. Utility capitalization policies are an ongoing concern for the Commission which warrants further investigation. However, given the broad scope of capitalization concerns, the Commission declines to require a[n] [interested person] proceeding or a limited investigation specific to DTE Electric, at this time.
>
> With the audit report now filed, the Commission plans to set forth its next steps in evaluating utility capitalization policies in a separate proceeding in the near future.[355]

Consistent with the Commission's determination that capitalization policies are of general concern, coupled with the Commission's intention to address these issues in a separate proceeding, this PFD finds that Staff's recommendations regarding a breakdown of inspection costs across all capital programs should be deferred to the more specific proceeding.

iii. LVD Lines Asset Relocation

Ms. Partlan testified that the Company's Asset Relocation subprogram includes capital investments to relocate LVD lines to accommodate road, building, and other third-party construction projects (for government agencies and private property owners), as well as internal Company projects.[356] It also includes Make-Ready work to prepare

---

[355] January 23, 2025 order in Case No. U-21534, p. 368, quoting November 18 order in Case No. U-20836. p. 471.

[356] 3 Tr 1914-1918.

LVD poles for third-party pole attachments (communications companies).[357] According to Ms. Partlan, this subprogram primarily functions to serve customer requests; however, reliability improves when old or obsolete equipment is replaced through this subprogram because of new equipment and implementation of the latest standards.[358]

Consumers projected capital expenditures of $97.911 million in the 16-month bridge period and $79.090 million in the test year for LVD Asset Relocations sub-program. Ms. Partlan explained that these projected capital expenditures are based on recent trends in the number of relocation requests, including expected increases in Make-Ready work as a result of federal grants to expand broadband, as well as projects set forth in Exhibits A-166 and A-167.[359]

Mr. Boutet testified that the LVD Lines Relocations sub-program is demonstrating "substantial increases in requested funding for this case."[360] He noted that the Company's proposal for investment in Make Ready work is $45.837 million in the bridge period for 3,728 work units and $39.265 million in the test year for 3,181 work units, calculating a cost of $12,295 per unit in the bridge period and $12,343 per unit in the test year.[361] Mr. Boutet testified that Staff does not support this level of spending in this investment category due to "a nearly 60% increase in unit costs when compared with the most recent approval for this investment category in . . . Case No. U-21585." According to him, in that case, the Commission approved a projected test year

[357] 3 Tr 1914.
[358] 3 Tr 1918.
[359] 3 Tr 1919-1922.
[360] 6 Tr 4365-4366.
[361] 6 Tr 4375 see also, 3 Tr 1922.

expenditure level of $7.302 million for 950 work units, which equates to a much lower cost of $7,686 per unit.[362]

Further, Mr. Boutet considered the Company's description of Make Ready work as "raising electric conductors and equipment, adding or manipulating down guys, effectively grounding streetlight brackets, raising or lowering existing communications attachments, and pole replacements," as work functions that "seemingly fit into a category of maintenance and/or modification work of existing infrastructure," that does not justify "such large cost escalations."[363] He explained that these types of large cost escalations have only recently been justified when the purchase of new equipment that is facing heavy inflationary and/or supply chain pressures, such as distribution transformers, are involved.[364] He further observed that the Company has not identified any material ways in which the nature of the work has changed.[365] Mr. Boutet, thus, recommended a disallowance on a unit-cost basis, adjusted for inflation as follows:

	Per Unit Cost From Case No. U-21585	**Staff-applied Inflationary Adjustment**	**Staff-proposed Per Unit Cost**	**Number of Units Proposed by Company**	**Company Total Proposed Investment**	**Staff Total Proposed Investment**	**Staff's Proposed Disallowance**
Bridge period	$7,585	2.1% for 12-month bridge period 2.4% for 4-month bridge period	$7,848 $7,911	3,728	$45.837M based on $12,295 unit cost	$21.942M $7.373M	($12.435M) ($4.086M)
Test Year	$7,585	2.4%	$8,100	3,181	$39.265M based on $12,343 unit cost	$25.769M	($13.495M)[366]

[362] 6 Tr 4375.
[363] 6 Tr 4376.
[364] 6 Tr 4376.
[365] 6 Tr 4376-4377.
[366] See Exhibit S-13.11; 6 Tr 4377.

ABATE witness York did not address LVD Make-Ready work specifically but, rather, testified that the Company's overall projected investment of $97.911 million in the LVD Asset Relocation subprogram for the bridge year and $79.090 million in the test year represent "a dramatic increase relative to the five-year average annual historical spend of $44.605 million and the 2024 actual spend of $51.502 million."[367] She expressed concern that the Company had identified specific projects which account for about $7 million of the projected expenditures in the bridge period and test year, but characterized the remaining projects as "highly uncertain" and "driven by requests from external stakeholders."[368] She also noted that the Company acknowledged that customer requested relocations, which are commonly associated with home remodeling work, slowed when interest rates rose at the end of 2023.[369] Citing this uncertainty, Ms. York recommended the Commission set the projected capital expenditures at the actual levels experienced by the Company in 2024, reducing projected capital expenditures by $46.409 million for the bridge period and $27.587 million for the test year.[370]

Mr. Coppola addressed the number of units for the LVD Make-Ready work that was originally addressed in Company witness Partlan's testimony, before it was revised.[371] Thus, Mr. Coppola's application of calculations to reach proposed disallowances were not based on the corrected data submitted by Ms. Partlan in her Revised Direct Testimony. Mr. Coppola recommended a bridge period disallowance and

[367] 6 Tr 3701, citing Exhibit A-113, line 38.
[368] 6 Tr 3701.
[369] 6 Tr 3701.
[370] 6 Tr 3701.
[371] See 3 Tr 1922; 6 Tr 2428; 3 Tr 2428-2430.

a test year disallowance that were revised in the Attorney General's initial brief, as discussed below.

In rebuttal, Ms. Partlan disagreed with Staff, ABATE, and the Attorney General. In response to Staff, Ms. Partlan explained that, in this category, Consumers typically recovers a percentage of the cost from the attaching third party. She stated that both the projected spending (set forth in Figure 16 in her direct testimony), and the historical costs (set forth in Exhibit A-130, page 2, line 40), reflect the Company's costs net of that recovery amount. She asserted that unit costs should be evaluated based on the total cost of the work, rather than the Company's responsibility alone for joint attachment requests.[372] She also testified that the Company's net 2023 unit costs appear artificially lower due to unusual customer contributions which offset 65% of spend, rather than then typical 46%-48%, due to a temporary increase in reimbursement from attaching parties driven by extensive rural expansion – making the Company's net 2023 unit costs appear artificially lower.[373] She further testified that these lower unit costs were "artificially lower" and informed the Commission's order in Case No. U-21585, which formed the basis of Mr. Boutet's recommendation.

In response to Mr. Coppola, Ms. Partlan noted that he was not using the corrected projected bridge period and test year unit count, which were provided in discovery and made part of her revised direct testimony.[374] She testified that the projected growth in federal broadband funding, was used for this projection.[375] She also testified that, in order to "assure that these numbers are not over-projected for 2025 or

[372] 3 Tr 2042.
[373] 3 Tr 2042.
[374] 3 Tr 2049; Exhibit A-225 (JMP-5)
[375] 3 Tr 2049.

2026," especially in light of possible 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."[376] Thus, she took exception to Mr. Coppola's representation that the Company's discovery response did not show calculations and his assertion that the Company did not support its projections.[377] Finally, aside from Mr. Coppola's use of the original information, not the Company's updated information, she noted that he miscalculated the Company's projected unit costs as $5,955 when it is actually $12,300 and objected to the use of the per unit cost as the basis of his analysis.[378]

Ms. Partlan also countered Ms. York's emphasis on the uncertain nature of spending that is driven by external parties, Ms. York's connection of that uncertainty to the slowing of remodeling work due to interest rates, and Ms. York's recommendation to reduce bridge and test year projections to 2024 actual spend levels. She explained that the spending is not entirely uncertain because the Company has, for a number of years, provided project lists only for LVD Asset Relocation projects tied to the Company's own HVD projects, since they are known to the Company in advance. Further, she noted that customer-requested work is only one part of the LVD Asset Relocation sub-program, and growth in customer-requested work only makes up a small part of the

[376] 3 Tr 2049.
[377] 3 Tr 2049.
[378] 3 Tr 2049-2050.

projected growth in LVD Asset Relocations.[379] She testified that "much more of the projected growth in LVD Asset Relocation is tied to growth in make-ready work[.]"[380]

The parties' briefs largely reiterate what was provided in testimony with a few notable exceptions. Clarifying Ms. Partlan's rebuttal, the Company's initial brief explains that its opposition to Staff's net unit cost methodology saying that it would be unreasonable to adopt Staff's approach because it assumes a much higher recovery from third parties than is expected based on the Company's historical experience.[381]

The Attorney General's initial brief recognized her failure to utilize the Company's revised work units for the bridge period and test year and reduced her recommendation to a proposed disallowance for the bridge period of $5.669 million from the previously recommended $26.382 million for the LVD Make-Ready work in the LVD Asset Relocation sub-program. She also withdrew her previous recommendation for an $18.639 million disallowance for the test year for the LVD Make-Ready work in the LVD Asset Relocation subprogram.[382]

Like the Company's LVD Lines New Business sub-program and LVD Lines Demand Failure sub-program, this PFD notes that Mr. Kelly testified regarding deferred accounting authorization for Asset Relocations. As he explained, "the largest factors influencing expenditures in [this] program[] are externally driven."[383] This means that the factors driving the spending in this subprogram are outside of the Company's control – thus, it is non-discretionary and are costs that the Company can't know in advance.

---

[379] 3 Tr 2064; Exhibit A-130 (MPK-20), line 38 for recent history of customer-requested work.
[380] 3 Tr 2064, citing Exhibit A-130 (MPK-20), line 40 for recent history of make-ready work and Figure 16 of direct testimony.
[381] Consumers' brief, p. 43.
[382] Attorney General brief, p. 46-47.
[383] 3 Tr 1470.

As noted above, the Company has requested that it be allowed to continue to defer the revenue requirement for any capital spending for this program above what is included in rates, if the spending exceeds what the Commission approves in this case, and it agreed to the same stipulations the Commission approved for deferred accounting treatment for these programs in Case No. U-21585.[384] These deferrals are reconciled in the Company's next rate case.

As discussed in Mr. Daly's testimony and shown in Exhibit A-85, Consumers projected total asset relocation costs of $52.5 million in Case No. U-21585, and actual costs were $53.3 million, indicating an accurate projection, despite Ms. Partlan's apparent concerns regarding the use of unit costs net of customer contributions in that case and in the instant case. Because this PFD does not find the use of a historical net unit cost methodology unreasonable, particularly in light of the distribution deferral mechanism, this PFD recommends approval of Staff's adjustment to the Company's proposed investment in LVD Lines Asset Relocation. This results in disallowances of $12.435 million and $4.086 million in the bridge period, and $13.459 million in the test year.

iv. LVD Reliability

According to Ms. Partlan, a portion of the Company's Reliability Program is geared toward line hardening, which is in turn part of the LVD Lines Reliability and Resiliency subprograms.[385] Ms. Partlan testified that to improve SAIDI, the Company is increasing investment in these subprograms relative to historical levels that predated

[384] 3 Tr 1470.
[385] 3 Tr 1924.

the Reliability Roadmap.[386] Ms. Partlan addressed investment in LVD Lines Reliability, LVD Repetitive Outages, LVD Lines Rehabilitation, and Resiliency. Mr. Kelly testified that the Company proposes to continue including LVD Lines Reliability investments previously approved by the Commission in its IRM, which is discussed later in this PFD.[387]

Staff, the Attorney General, ABATE, and MNSC recommended various adjustments to these subprograms and certain spend categories. These adjustments are discussed below.

LVD Lines Reliability

Ms. Partlan provided a detailed review of the LVD Reliability Program, testifying that the purpose of program is "to ensure the long-term safe and reliable operation of the electric distribution system, and to support the Company's SAIDI glidepath[.]" again referencing modeling in the Reliability Roadmap as support.[388]

Ms. Partlan referenced Mr. Kelly's testimony on the Reliability Roadmap and further explained that Consumers' increase in its spending in the LVD Reliability subprograms is based on increasingly severe weather and the need to increase reliability in the face of this worsening weather.[389] Ms. Partlan testified that the LVD Lines Reliability subprogram is comprised of five spend categories: 1) targeted circuit improvements; 2) pole replacements; 3) ATR loops; 4) circuit exit enhancements; and 5)

[386] 3 Tr 1924-1926.
[387] 3 Tr 1473.
[388] 3 Tr 1924.
[389] 3 Tr 1924-1925.

ROW and easement acquisition.[390] Projected capital expenditures are $180.763 million in the bridge period and $312.886 million in the test year for LVD Lines Reliability.[391]

Recommendations for disallowances were made to the Company's proposed investment in targeted circuit improvements and proposals to maintain historical expenditure amounts were made for the Company's ROW and easement acquisitions investment proposal.

For Targeted Circuit Improvements, the largest spending category in the LVD Lines Reliability subprogram, Ms. Partlan explained that investments are made to 1) reduce the amount of non-standard voltage on the distribution system; 2) improve zonal health; 3) convert open-wire secondary to multiplex; and 4) rejuvenate vintage underground cable.[392] Ms. Partlan then discussed the approaches the Company uses to address these concerns as well as the benefits of doing so. Mr. Kelly testified in support of the Company's proposal to continue to include Targeted Circuit Improvements in the Company's proposed IRM.[393]

Ms. Partlan and Mr. Kelly discussed the Company's proposal to reduce non-standard voltage.[394] As set forth in the Company's Reliability Roadmap, non-standard voltages restrict the Company's ability to install transfers between circuits and modernize the grid in a streamlined fashion because circuits of different voltages cannot be connected.[395] The Company plans to invest $33 million per year over the next 10

---

[390] 3 Tr 1931.
[391] 3 Tr 3 Tr 1958; Exhibits A-166 (JMP-1) and A-167 (JMP-2).
[392] 3 Tr 1931-1932.
[393] 3 Tr 1473.
[394] 3 Tr 1933-1934;
[395] Exhibit A-129, p. 54.

years to convert at least 165 miles per year of non-standard voltage overhead lines, with an end goal of converting all non-standard voltages.[396]

Ms. Partlan discussed reliability improvements that are anticipated through reduction in non-standard voltage, including reduced system losses and increased system line capacity, reduced numbers of interrupted customers for single-phase faults, increased system load transfer ability, and reduced equipment inventory.[397] Additionally, as described more fully in the Company's Mitigating Wildfire Risk report, sponsored by Mr. Kelly, conversion of non-standard components with help address safety risks associate with wildfires ignited by ungrounded wires.[398]

The Company forecasted capital expenditures of $33.115 million for the projected test year and $8.427 million for the bridge period for the Company's voltage conversion sub-program.[399]

No party disputed these proposed investments and, therefore, this PFD recommends approval of the Company's voltage conversion sub-program.

Turning to Zonal Health Investment, some of the large increases in investment in the LVD Lines Reliability subprogram are driven by increased investments in zonal health improvements (as part of the Targeted Circuit Improvements) and pole replacements (which will be discussed later).[400] The Company forecasted capital expenditures of $61.320 million for the bridge period and $34.917 million for the

[396] Exhibit A-129, p. 55.
[397] 3 Tr 1932-1933.
[398] Exhibit A-132, p. 32.
[399] Exhibit A-167 (JMP-2), p 2; Exhibit A-166 (JMP-1), p.12.
[400] 3 Tr 1955.

projected test year for the Company's Zonal Health program.[401] Ms. Partlan explained that "[t]he Company's analysis has shown that 91% of customer interruptions happen on just 25% of line miles. Because of this, the Company focuses on or "targets" individual zones when assessing LVD asset health and mitigating the risk, instead of whole circuits."[402] Regarding the benefits of Zonal Health Investments, Ms. Partlan testified:

> Zonal health investments improve the reliability of the Company's LVD system by reducing the likelihood of an additional interruption over the next five years or more. A zone targeted for improvement can include multiple protective device zones or a single protective device zone. When the Company is aware that a circuit has deficiencies, based on outage data, then the Company inspects the overhead lines on affected circuits.[403]

Ms. Partlan provided a list of possible solutions for problem zones, including system protection upgrades and replacements; replacing poles and other equipment at EOL; installing upgrades to improve voltage quality; relocating lines; and restoring underground cable that is no longer looped to establish redundancy, among other interventions.[404]

Turning to the benefits of Zonal Health improvements, Ms. Partlan presented a comparison of three years of outage history for zones, prior to investment, to the outage history for one to three years after investment (from 2019-2022). The weighted average of the results demonstrated a 53% improvement after investment. [405] Ms. Partlan further explained that the Reliability Roadmap provides "a plan to address all zones with a zonal health score of 10 or greater, meaning each of these zones will need

---

[401] Exhibit A-166 (JMP-1), p 11, line 82; Exhibit A-167 (JMP-2), p.5, line 44.
[402] 3 Tr 1934.
[403] 3 Tr 1936.
[404] 3 Tr 1938.
[405] 3 Tr 1938, Figure 23.

investment."[406] The Company plans to do this work over 20 years, with a ramp-up in investment to address approximately 280 zones per year.[407]

Although Staff witness Boutet testified that the Company provided more information about its proposed Zonal Health Improvements than it did in Case No. U-21585, and the Company proved that it successfully spent $34.243 million in this investment category in 2024, he found the Company's discussion and analysis of the most cost-effective approaches to improving reliability to be lacking.[408] While he recognized that the Zonal Health projects are identified by the Company's Reliability Analytics Engine (RAE), he expressed concern that the RAE "only ranks Zonal Health projects against each other to determine prioritization of these projects," and said, "[i]t is not evident that the RAE considers other approaches outside of Zonal Health projects."[409]

Mr. Boutet supported the Company's proposed test year expenditures for the Company's LVD Lines Reliability subprogram investment in Zonal Health. He, however, recommended bridge period disallowances totaling $14.76 million.[410] Mr. Boutet reasoned that the bridge period adjustment "will align annual spending levels between the test year and the bridge period."[411] He concluded that it "would be reasonable to allow the Company to continue work at a pace proven to be attainable in 2024 while

[406] 3 Tr 1941.
[407] 3 Tr 1941.
[408] 6 Tr 4372.
[409] 6 Tr 4372.
[410] 6 Tr 4373.
[411] 6 Tr 4373.

awaiting further support and details regarding impacts of Zonal Health Improvements."[412]

In rebuttal, Ms. Partlan disagreed with Staff, submitting that the RAE does not rank Zonal Health Improvements projects against one another but, rather, 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."[413] She explained that the RAE is just one tool used to identify projects and further explained that 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."[414] When a zone reliability issue is identified that the Company determines "is worth fixing so that customers experience fewer interruptions," the "least-cost-best-fit approach is then used to identify the most cost-effective manner of doing so, regardless of the specific approach ultimately selected.[415] Thus, Ms. Partlan asserted that "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." Citing the "clear benefits" the Zonal Health Improvement projects have demonstrated, Ms. Partlan expressed disagreement with Staff's position that the work must stay level until the impacts of the work are better substantiated. Thus, she urged

[412] 6 Tr 4373.
[413] 3 Tr 2039-2040.
[414] 3 Tr 2040.
[415] 3 Tr 2040.

the Commission to reject Staff's recommendation for disallowances in the bridge period.[416]

Mr. Coppola recommended a disallowance of $27.304 million for the bridge period and $22.652 million for the projected test year for the Company's Zonal Health improvements program.[417] Mr. Coppola viewed the Company's proposed capital expenditures through the lens of unit cost saying that the Company's forecasts reflect a unit cost of $123,380 for the bridge period and $199,525 for the projected test year.[418] Focusing on the number of units of work from 2021 to 2024, Mr. Coppola testified that the Company's number of units ranged from 169 in 2021 to 10,509 in 2022, with 7,749 units in 2023; and 511 in 2024.[419]

He attributed the higher volume of work units in 2022 and 2023 to the installation of fuses on the lines, which are "high volume and lower cost."[420] He also noted that the Company's bridge period unit number is 497, and projected test year unit number is 175.[421] Mr. Coppola also noted that in 2024, the Company completed 511 units at a cost of $33.988 million for a calculated unit cost of $66,513, which is comparable to the 497 units forecasted by the Company for the bridge period and the 175 units forecasted for the projected test year.[422] He expressed concern, however that the "unit cost is considerably divergent with the forecasted unit cost of $123,380 for the bridge period

---

[416] 3 Tr 2040-2041; citing Figure 23 of Partlan direct testimony.
[417] 3 Tr 2431-2432.
[418] 3 Tr 2430-2431.
[419] 3 Tr 2430-2431.
[420] 3 Tr 2431.
[421] 3 Tr 2430.
[422] 3 Tr 2431.

being nearly double the historical unit cost for 2024 and the projected test year unit cost of $199,525 being nearly three times the 2024 historical cost."[423]

Stating that the Company had not provided justification for the "large variance in unit cost from one year to the next or what changed in the projects that increases the cost significantly," Mr. Coppola recommended the use of the historical unit cost of $66,513, adjusted for inflation for a total bridge period unit cost of $68,442 and total projected test year unit cost of $70,085 to arrive at the proposed $22.652 million disallowance for the bridge period and $27.304 million disallowance for the projected test year.[424]

In rebuttal, Ms. Partlan noted the "very diverse portfolio of projects" observing that "defining a number of units for the entire portfolio of Zonal Health Improvement projects is difficult to do."[425] Referencing Exhibits A-166 and A-167, Ms. Partlan noted that some investments are identified by project, others address a certain number of line miles, others are defined by number of poles, and still others involve a certain number of fuses.[426] She opined that 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."[427]

Although the Company has provided more information in this case than in Case No. U-21585, like U-21585, the Company's evidentiary case in support of its Zonal

---

[423] 3 Tr 2431.
[424] 3 Tr 2431-2432.
[425] 3 Tr 2050, citing Footnote to Figure 35 of her direct testimony and Exhibits A-166 and A-167 indicating "the 497 bridge period units and the 175 test year units just reflect the number of line items" in the exhibits.
[426] 3 Tr 2050.
[427] 3 Tr 2050-2051.

Health Improvement unfortunately remains unclear – particularly for the bridge period. In its order in Case No. U-21585, the Commission asked for more analysis of the most cost-effective opportunities to drive improvements in reliability performance. This PFD notes that the Company states that it expects to make Zonal Health Improvements over a period of 20 years, with a ramp-up in investment to address approximately 280 zones per year. The Company's Exhibits A-166 and A-167 make it difficult to assess the number of "zones" that are included in the bridge period and projected test year, to assess what types of work units are included in a work zone, as both exhibits are presented by itemizing the "unit type" without a clear idea of the number of work units and types of work units in each zone. This is likely the reason that Staff and the Attorney General approached the significantly higher costs of the bridge period differently.

This PFD does not find the cost per work unit approach of the Attorney General to be the best method to analyze the reasonableness of the costs, particularly in light of the wide range of cost elements involved in the Zonal Health subprogram. This PFD also does not find Staff's approach to be optimal. This PFD notes that while Staff's concerns regarding the Company's use of the RAE as an input to identify zones needing improvement seems to somewhat align with what the Commission wanted to see in Case No. U-21585, it is not clear that Staff's request will be helpful in identifying the reasonableness of the investments proposed by the Company.

As the evidence in this matter demonstrates, the Company spent $34.243 million in this investment category in 2024, which is consistent with the proposed spending in the projected test year of $34.917 million. This PFD finds the Company's presentation

of the zones that were covered with the 2024 investments and the types of work units that were included in those zones to be lacking and unclear. This lack of clarity makes it difficult to determine why certain zones were chosen, whether there is consistency in zones and types of work units to either support the elevated spending suggested for the bridge period or the proposed investment for the projected test year. That being said, this PFD finds Staff's proposed approval of the projected test year to be reasonable as it is consistent with 2024 spending and recommends that the Commission approve the Company's proposed investment in Zonal Health for the projected test year. This PFD also agrees that Staff's rationale for a proposed disallowance for the bridge period is the most reasonable approach as it attempts to balance historical actual investment with that proposed by the Company and recommends that the Commission approve the Company's proposed bridge period investment (and proposed disallowances) in Zonal Health with the adjustments proposed by Staff and Staff's recommendation for additional detail in the future regarding impacts of Zonal Health Improvements.

Next, Ms. Partlan addressed Converting Open-Wire Secondary to Multiplex, which she stated will also deliver non-reliability benefits to customers, particularly in vulnerable communities.[428] The Company forecasted capital expenditures of $19.680 million for the bridge period and $14.670 million for the projected test year for this spend category.[429]

[428] 3 Tr 1955-1956
[429] Exhibit A-166, p. 12; Exhibit A-167, p. 6;

Ms. Partlan explained that, as discussed in the Reliability Roadmap, secondary assets – located between the distribution transformer and customer meter – are more challenging to repair than primary assets.[430] She testified:

> This challenge is most prevalent on open-wire secondary, much of which is approaching the end of its life, and is brittle and not easily repaired, and thus is more vulnerable to tree damage. Individual outages on the secondary system may not affect large numbers of customers, but they are high-frequency and long in duration. As demonstrated in Figure 25 [], open-wire secondary has a disproportionately high impact on vulnerable communities.[431]

Ms. Partlan further testified that the Company plans to programmatically convert its open-wire secondary to multiplex secondary, focusing on circuits with the highest risk scores, while ensuring and prioritizing equitable investment into vulnerable communities.[432] In support of the Company's conversion program, Ms. Partlan said that the Commission approved one half of the Company's initially proposed investment in open-wire conversion in Case No. U-21585, approximately $14.4 million per year, which is in line with the proposed investment in this case.[433]

According to Ms. Partlan, the benefits of this investment include improved safety by reducing the occurrence of difficult-to-repair wire downs, and greater capacity, reducing the number of future upgrades that would be needed when customers adopt new technologies, such as heating electrification or EV charging – both of which will focus on helping customers in vulnerable communities.[434] Ms. Partlan noted that while

---

[430] 3 Tr 1941-1942.
[431] 3 Tr 1942.
[432] 3 Tr 1942-1943; Exhibit A-166 (JMP-1), page 12; Exhibit A-167 (JMP-2), page 6.
[433] 3 Tr 1943-1943.
[434] 3 Tr 1943-1944.

the impact to systemwide SAIDI is modest, the outage duration benefits for the impacted customers will be more substantial.[435]

Mr. Coppola challenged the Company's projected test year units saying that one of the Company's discovery responses demonstrates that the Company only projected 165 units rather than the 283 (shown on Figure 35 of Ms. Partlan's direct testimony).[436] He, thus, recommended a disallowance of $2.267 million in the bridge period and $9.462 million in the projected test year based on adjustments to the unit costs to not only adjust the number of units in the test year from 283 to 165, but also to adjust unit costs to be more consistent with 2024 actuals.[437]

In rebuttal, Ms. Partlan objected to the Attorney General's proposed disallowances explaining that the discovery request from 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.[438] Thus, citing to Exhibit A-167, page 2, she stated that the actual workplan for the test year demonstrates 283 miles of work, which is the correct unit to use for the test year.[439] She then calculated the unit cost based on 283 work units to arrive at a unit cost of $117,014 per mile, which she noted is "in fact lower than the actual unit cost for 2024," making Mr. Coppola's proposed disallowances without merit.

---

[435] 3 Tr 1944.
[436] Exhibit AG-4; 3 Tr 2432-2434 (using 2024 unit cost of $136,044 and applying an inflation factor of 2.9%).
[437] 3 Tr 2433-2434.
[438] 3 Tr 2051.
[439] 3 Tr 2051-2052.

The parties' briefs reflect and reiterate the positions of the parties made in their respective testimony and exhibits.[440].

This PFD agrees with the Company. It appears that the discovery request did ask for calendar year information for this investment. Thus, while Exhibit AG-4, page 3 reflects the Company's data, page 4 reflects the calendar year information requested by the Attorney General. This PFD agrees that utilizing a calendar year analysis creates a misalignment of actual forecasts made by the Company and does not reflect an error in the Company's proposed work units. Thus, this PFD recommends the Commission approve the Company's proposed bridge period and projected test year investment in voltage conversions and open-wire secondary conversions to multiplex and reject the proposed disallowances of the Attorney General.

Ms. Partlan next discussed spending for Rejuvenating Vintage Underground Cable, explaining that approximately 2,500 miles of the 9,500 miles of underground primary cable on the Company's system are composed of 15 kV vintage cable that predates the 1980s and is unjacketed, leaving the neutral conductors exposed to accelerated deterioration from exposure to soil and moisture.[441] Thus, as explained by Ms. Partlan, while underground distribution lines provide many benefits, cable that eventually degrades presents a heightened risk of failure.[442]

According to Ms. Partlan, the Company has identified larger concentrations of critical areas in need of attention. This includes concentrations in Grand Rapids, Flint,

---

[440] Consumers' brief, p 49; Attorney General's brief, pp. 50-53.
[441] 3 Tr 1944.
[442] 3 Tr 1944.

Traverse City, and Kalamazoo.[443] To address these issues, Consumers has begun utilizing cable injection to rejuvenate the underground cable. Ms. Partlan testified that this is less expensive than cable replacement and is expected to extend the life of the cable by a minimum of 25 additional years. Having started these investments in Grand Rapids and Flint (as it is most cost-effective to complete all work in one area before moving to a new location), the Company plans to begin working in Traverse City in 2026.[444]

The Company plans to rejuvenate all 15 kV cable installed between 1960s and 1980s over a period of nine years beginning in 2025, with a ramp-up to investing up to $165 million each year.[445] Ms. Partlan explained that the Liberty Audit highlighted the successes of vintage underground cable rejuvenation concluding that this work "reflects a sound means for addressing vintage underground cable reliability problems."[446] The Company's proposed investment in Rejuvenating Vintage Underground Cable is $27.909 million in the bridge period and $65.989 million in the projected test year.[447]

For Underground Cable Rejuvenation work, Mr. Coppola again looked at the Company's proposed investment through the lens of a cost per project. Mr. Coppola calculated an average unit cost of $410,426 ($27.909 million divided by 68 projects) for the bridge period and an average unit cost of $417,652 ($65.989 million divided by 158 projects) for the projected test year. He then compared the historical unit costs in the four years from 2021 through 2024, testifying that they ranged from $90,664 to

---

[443] 3 Tr 1945-1946; Figures 27, 28.
[444] 3 Tr 1946.
[445] 3 Tr 1946.
[446] 3 Tr 1947 citing Liberty Audit from Case No. U-21305.
[447] Exhibit A-166, p 12; Exhibit A-167, p. 6.

$224,660 per unit with the number of projects ranging from 5 to 10 annually. He calculated the average unit cost in the most recent three years to be $161,392 and also testified that the average unit cost for 2024 was $168,852.[448]

Because Mr. Coppola considered the forecasted unit costs based on the forecasted spending and planned number of units to be excessive and not adequately supported, he recommended a capital expenditure reduction of $16.616 million in the bridge period and $39.120 million in the test yea saying that the unit costs need to "be moderated."[449]

ABATE witness Fitzhenry testified that he believed the Company did not quantify the benefits of rejuvenating vintage underground cable "despite requesting an additional $38,080,000 in capital expenditures in the test year above amounts included in the bridge period."[450] He also asserted that the vintage underground cable rejuvenation project does not provide immediate safety or reliability benefits. Mr. Fitzhenry characterized the project as more akin to "preventative maintenance, which would only provide future benefits in the event that an existing underground cable fails."[451] Mr. Fitzhenry, thus, recommended that the Commission disallow test year investments in underground cable rejuvenation above what is in the bridge period, amounting to a reduction of $45.057 million in the test year.[452] He also recommended that the Commission specifically remove it from the IRM, which will be discussed later in this PFD.

---

[448] 3 Tr 2434.
[449] 3 Tr 2434.
[450] 6 Tr 3724.
[451] 6 Tr 3724.
[452] 6 Tr 3724-3725 (also discussing the Company's use of the IRM and asking for a similar disallowance of $45.057 for the year after the projected test year).

In rebuttal to the Attorney General, Ms. Partlan testified that Mr. Coppola's unit cost analysis appears to be based on a comparison of the units the Company provided in a discovery response with the units in Figure 35 of Company witness Partlan's direct testimony which depicted units by mile.[453] Ms. Partlan then explained that when using 50 miles for the units in the discovery response for an accurate comparison, the Company's four-year average unit case has been $646,720, which is higher than the unit cost the Company is projecting for the bridge period and test year.[454]

In rebuttal to ABATE, Ms. Partlan objected to Mr. Fitzhenry's assertion that this work does not provide safety or reliability benefits. She reiterated that the Underground Cable Rejuvenation program targets cable that is starting to deteriorate, even if it has not yet failed, and also reiterated that the vintage cable that predates the 1980s is at a higher risk of deterioration and failure. Ms. Partlan noted that investments in the Demand Failures program addresses situations where an asset has already failed and that the investment in this program is to prevent an outage in the future. She continued by saying that 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 work would be more expensive and when customers would have to deal with an interruption of service."[455] She concluded by noting that the Audit deemed the underground cable rejuvenation program to be a "sound means of addressing reliability issues, and that the Company has had success with it to date."[456]

---

[453] 3 Tr 2052.
[454] 3 Tr 2052-2053; see Table 3.
[455] 3 Tr 2067.
[456] 3 Tr 2067.

Thus, she encouraged the Commission to reject the proposed reductions suggested by both the Attorney General and ABATE.

The parties' briefs largely reiterate the information and position set forth in their testimony and exhibits.[457]

This PFD agrees with the Company that the Attorney General's comparison misaligns the Company's use of miles by instead using units in her comparison, thus making it appear that the per unit cost of this program is excessive when, in fact, it is consistent with prior years. Further this PFD does not find ABATE's argument to be persuasive and agrees that this program, that seeks to pre-emptively improve reliability for customers rather than wait for cable failure, and ensuing outages, is valuable. Thus, this PFD recommends that the Commission reject the disallowances proposed by the Attorney general and ABATE and approve the capital investment in the Company's Underground Cable Rejuvenation program.

Turning to the Pole Replacements spend category under the LVD Lines Reliability subprogram, Ms. Partlan testified that replacing poles prior to failure delivers significant benefits for public and employee safety as falling poles can create a major public safety hazard, threatening both people and property – including line workers.[458] Ms. Partlan explained that the Company's pole replacement portion of the Company's LVD Lines Reliability subprogram has two components – poles replaced in response to prior inspection results from previous years that identified poles at risk of failure, and the new Reliability Roadmap program of groundline inspections of poles.[459] Groundline

[457] Consumers brief, pp. 49-52; ABATE's brief, pp. 25-26; Attorney General brief, pp. 53-54.
[458] 3 Tr 1949.
[459] 3 Tr 1947.

Inspection of poles involves the Company's plans to replace all rejected poles identified through a groundline inspection on a 12-year cycle or through the regular two-year visual inspection cycle of whole circuits.[460] Ms. Partlan explained that, while these inspections are underway, the Company will continue to replace LVD poles identified in inspections that have not yet been completed.[461]

Based on data related to the vintage of poles on the Company's system, and the typical rejection rates of poles of a given vintage, the Company estimates that approximately 10% of the poles on the LVD system will be classified as rejected based on these inspections and, as a result, the Company projects that these inspections will identify 12,500 LVD poles per year for replacement.[462] Ms. Partlan further explained that the highest risk poles carry a rejection rate of 15% or greater, and moderate risk poles carry a rejection rate of 10% to 15%.[463] Additionally, she stated that the replacement of a pole prior to failure avoids interruption of electric service to customers and is considerably less expensive than replacing a pole after failure.[464] Finally, in addition to this replacement plan, the Company is also taking action to improve LVD poles as set forth in the Company's Reliability Roadmap by upgrading its minimum pole standards which will also have a longer design life.[465] The Company proposes an investment in Pole Replacement in the bridge period of $29.711 million and the projected test year of $127.500 million.[466]

---

[460] 3 Tr 1947.
[461] 3 Tr 1947-1948.
[462] 3 Tr 1948.
[463] 3 Tr 1948.
[464] 3 Tr 1949.
[465] 3 Tr 1950.
[466] 3 Tr 1956, Figure 35; Exhibit A-166 (JMP-1), p. 2; Exhibit A-167 (JMP-2), p. 6.

Mr. Fitzhenry recommended the Commission adopt a 5% rejection rate for the LVD Pole Replacement sub-program, rather than the Company's proposed 10% rejection rate, reducing capital expenses for pole replacement by 50% and reducing IRM capital expenditure by $63.750 million in the test year and thereafter.[467] Mr. Fitzhenry took issue with Consumers' sole reliance on age for forecasted rejection rate for pole replacement.[468] He recommended the Company forecast the rejection rate for poles by relying on a sample of pole inspections.[469] Absent this method, Mr. Fitzhenry recommended the Company adopt a 5% rejection rate saying that "[t]his is at the higher end of rejection rates when comparing the actual rejection rates of utilities who have utilized groundline inspections for pole replacement."[470]

MNSC witness Jester viewed LVD Pole Replacements as "the most important and obvious" category that might be considered "surge costs."[471] His recommendation to deem baseline LVD pole replacement costs to be $25 million with all pole replacement costs in excess of that to be considered surge expenditures to be deferred and eventually securitized, will be addressed separately below. Similarly, CUB witness Bunch discussed LVD Pole Replacement through the lens of test year baseline spending of $25 million with a $102.5 million surge amount, which will also be discussed separately below.

---

[467] 6 Tr 3712.
[468] 6 Tr 3722.
[469] 6 Tr 3722-3723.
[470] 6 Tr 3723.
[471] 6 Tr 3996.

In rebuttal, Ms. Partlan disagreed with Mr. Fitzhenry saying that "the Company is not proposing to use age as the deciding factor in replacing LVD poles."[472] She clarified that poles will only be replaced if they are rejected according to NESC criteria following inspection.[473] She stated that the Liberty Audit's perspective was not to "ignore age in developing strategies or assumption about the likely state of the system, with those assumptions to be validated by inspection."[474] Ms. Partlan explained that age is a reasonable proxy in developing this kind of analysis, since age is correlated with deterioration of wood.[475] She further explained that the Company did not arrive at 10% arbitrarily but, rather, based this figure on its assessment of the likely average condition of poles of given vintages based on research conducted by the Electric Power Research Institute (EPRI).[476]

The parties briefs largely address the information contained in their testimony and exhibits.[477]

This PFD does not find ABATE's argument to be persuasive and recommends that the Commission approve the Company's LVD Pole Replacement sub-program and reject ABATE's proposed disallowances.

Addressing the Automation Transfer Recloser (ATR) Loop spend category, Ms. Partlan explained that an ATR is a set of reclosers installed between adjacent circuits that work simultaneously to automatically restore power to many impacted customers

---

[472] 3 Tr 2065.
[473] 3 Tr 2065.
[474] 3 Tr 2065.
[475] 3 Tr 2065.
[476] 3 Tr 2066.
[477] Consumers' brief, pp. 50-51; ABATE's brief, pp. 23-24.

when power loss is detected.[478] An ATR Loop recloser control includes additional programming beyond a standard recloser which allows it to automatically open and close the strategically placed reclosers to enable impacted customers to be fed from the adjacent source within the loop.[479] Ms. Partlan emphasized that "[t]his automated, fast response is the key factor driving customer reliability benefits."[480]

Although ATR Loops were part of the Company's Grid Automation/Modernization program, they have been moved to the LVD Lines Reliability subprogram. Ms. Partlan explained that, as of March 2023, there were 154 ATR Loops in service providing over 216,000 customers with "a self-healing smart grid that prevents or minimizes the impacts of outages."[481] The Company proposes an investment in the ATR Loops program of $25.616 million in the bridge period and $15.412 million in the projected test year.[482] No parties addressed or disputed the investments in these projects and, therefore, this PFD recommends the Commission approve this investment.

Lastly, Ms. Partlan addressed Circuit Exit Enhancements and Rights of Way (ROW) Projects, testifying that the Company installs circuit exits on each phase outside the substation fence, which provides additional safety by creating an isolation point for line workers in case the substation and/or substation equipment become energized.[483]

She also testified in support of the Company's investment in ROW projects which are used to procure necessary land or land rights for LVD projects, including both lines

---

[478] 3 Tr 1951-1952; Figure 32 at 3 Tr 1952.
[479] 3 Tr 1952.
[480] 3 Tr 1952.
[481] 3 Tr 1952-1953; Figure 33 at 3 Tr 1953.
[482] Exhibit A-166 (JMP-1), p.14; Exhibit A-167 (JMP-2), p. 10.
[483] 3 Tr 1953.

and substations.[484] The Company proposes investment in the Circuit Exit Enhancement project of $1.911 million in the bridge period and $3.616 million in the projected test year.[485] The Company proposes investment in the ROW projects of $6.188 million in the bridge period and $17.667 million in the projected test year.[486]

Mr. Boutet and Mr. Coppola testified that Consumers did not support its projected test year spending for ROW stating that the Company provided no details about specific ROW projects and only indicated that costs are projected based on a percentage of Targeted Circuit Improvement spending.[487] Pointing to Exhibit S-13.9, Mr. Boutet testified that the Company, in discovery, responded that there are no individual projects in the ROW category and that costs are developed according to a percentage of the Targeted Circuit Improvement investment category. Thus, Staff and the Attorney General recommend approval of the Company's bridge period investment as it is based on previous test year approvals in Case No. U-21585.

Staff proposed a test year expenditure in this case of $4.891 million based on inflation adjustments to the approved test year in Case No. U-21585, which is a $12.776 million disallowance for the projected test year.[488] The Attorney General proposed the use of the highest level of ROW costs in the past four years of $6.202 million, which occurred in 2024, which is an $11.465 million disallowance for the projected test year.[489]

In rebuttal, Ms. Partlan disagreed with Staff and the Attorney General and asserted that additional explanation for the projects was provided in discovery and is set

---

[484] 3 Tr 1953-1954.
[485] Exhibit A-166 (JMP-1), p. 13; Exhibit A-167 (JMP-2), p. 9.
[486] 3 Tr 1953-1954; 3 Tr 1956, Figure 35.
[487] 6 Tr 4378; 3 Tr 2435-2437.
[488] 6 Tr 4379.
[489] 3 Tr 2436.

forth in Staff's Exhibit S-13.9.[490] She further explained that ROW expenditures include items such as research prior to designs to understand the rights that the Company already has, as well as the creation of easement documents for new easements (and payments for easements). She noted that:

> [T]he 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.[491]

Ms. Partlan concluded that the Company's projections, based on a historical spending percentage, represents a reasonable method for projecting these ROW costs, and further emphasized that ROW spending is increasing due to increases in the overall LVD Lines Reliability sub-program.[492]

The parties' briefs reiterate the testimony and exhibits found in their testimony.[493]

This PFD finds the arguments of Staff and the Attorney General to be persuasive. It is notable that in the Company's last rate case, Case No. U-21585, the Commission criticized the Company for its failure to provide adequate support for these investments. While the Company points to the discovery response (Exhibit S-13.9) as evidence of further support, this PFD disagrees that the information provided in this discovery response is sufficient evidence to support the proposed test year expenditures. This PFD finds the historical approach utilized by the Attorney General to be the most reasonable approach to establishing a proposed test year investment for

---

[490] 3 Tr 2043; 2053.
[491] 3 Tr 2043.
[492] 3 Tr 2044.
[493] Consumers brief, pp. 52; Staff brief, pp. 11-13; Attorney General brief, pp. 54-56.

the Company's ROW projects. This approach, as an alternative, was also supported by Staff in its initial brief.[494]

Because no party took issue with or objected to the proposed investment in the Company's Circuit Exit Enhancement project, this PFD recommends the Commission approve the Company's investment of $1.911 million in the bridge period and $3.616 million in the projected test year for this project.[495] Further, because there is was no objection, this PFD recommends approval of the Company's proposed investment in the ROW projects of $6.188 million in the bridge period. Finally, this PFD recommends approval of $6.202 million in investment in the Company's ROW projects which represents a $11.465 million disallowance for the projected test year in this investment category.

LVD Lines Repetitive Outages

Ms. Partlan testified that the LVD Repetitive Outages subprogram is like the LVD Lines Reliability subprogram in the types of work performed and in how projects are identified; however, it is designed to specifically address areas of the distribution system that consistently experience recurring customer interruptions, measured by all-weather CEMI.[496]

The Commission's Service Quality and Reliability Standards specify that utility performance is unacceptable if more than 6% of customers have four or more outages in a calendar year (CEMI-4+), and provide bill credits for customers with too-frequent

[494] Staff's brief, p. 13.
[495] Exhibit A-166 (JMP-1), p. 13; Exhibit A-167 (JMP-2), p. 9.
[496] 3 Tr 1960-61.

outages.[497] The Company projected a CEMI-4 of 8.2% in 2026 based on the overall investment plan as approved by the Commission in Case No. U-21585. According to Ms. Partlan, Consumers needs to spend an additional $33.2 million in 2026 and $23.0 million in 2027 to achieve the standard beyond 2026, which is reflected in the Company's projected bridge period and test year investment levels in the instant case.[498] The Company is projecting LVD Repetitive Outages capital expenditures of $21,089,000 in the bridge period, and $30,344,000 in the test year, completing 246 projects in the bridge period and 337 projects in the test year.[499]

Ms. Partlan explained that to mitigate repetitive outages for each 1% of customers for which CEMI performance is short of the Commission's standard, the Company will have to address 161 zones at the cost of $14.45 million.[500] Ms. Partlan stated that investments could include: system protection upgrades; replacing deteriorated or non-standard equipment; relocating portions of lines from dense tree or other poor access conditions; upgrading conductors at risk of contact with trees; and relocating portions of overhead lines underground to reduce tree-related and severe weather interruptions. By targeting investment to the worst performing areas of the distribution system, the Company expects to improve SAIDI, SAIFI, and CEMI, reducing outage length and frequency of outages experienced by customers.[501]

Ms. Partlan stated that the Company used RAE data to decide where to invest to achieve the greatest reliability benefit for the highest number of customers first, which

---

[497] 3 Tr 1961.
[498] 3 Tr 1962.
[499] 3 Tr 1965.
[500] 3 Tr 1962.
[501] 3 Tr 1962-64.

would meaningfully improve CEMI.[502] The Company also used feedback from field operations and focused on customers experiencing CEMI-4+, prioritizing them for projects in this subprogram.[503] Ms. Partlan also noted that the Company developed the projected costs of the projects by considering typical costs for materials and labor, and the Company's previous experience performing similar projects. She further stated that the Company is shifting investments within this subprogram to focus on more robust, and more expensive, hardening projects such as line relocation, undergrounding, and replacing bare wire with tree resistant wire.[504]

Mr. Boutet addressed the Company's Repetitive Outages subprogram, stating that Staff does not support Consumers' proposal because the Company has demonstrated significant underspending in this subprogram in the two most recent rate cases. For calendar year 2023, the Company projected spending $9.587 million on its Repetitive Outages subprogram in Case No. U-21389; however, in the subsequent rate case, MPSC Case No. U-21585, the Company reported 2023 actual spending of $4.082 million, a 57% underspend.

Similarly, for calendar year 2024, Consumers projected spending of $9.856 million for this subprogram in Case No. U-21585. However, in this case the Company reported 2024 actual spending of $4.491 million, a 54% underspend. Therefore, Mr. Boutet testified that the Company has not demonstrated it can successfully undertake

[502] 3 Tr 1964-65.
[503] 3 Tr 1965.
[504] 3 Tr 1967; Exhibits A-166, A-167.

its projected spending when it has in recent history been unable to spend one-third of this projection despite Commission approval.[505]

Accordingly, Mr. Boutet recommended a 20% disallowance to both the bridge period and test year projections for the Repetitive Outages subprogram, which equates to a $2.002 million disallowance to the 12-month bridge period, a $2.215 million disallowance to the 4-month bridge period, and a $6.068 million disallowance to the test year.[506] He explained that this proposal represented a compromise between the evident recent underspending by the Company and the recognition by the Commission in its Order in Case No. U-21585 that this subprogram is valuable to the Company's CEMI-4.[507]

In rebuttal, Ms. Partlan acknowledged Staff's recommendation as a compromise between the recent underspending and the importance of the work in meeting the Commission's CEMI-4 standard; but she nevertheless disagreed.[508] She stated that Staff's approach was flawed to the extent it assumed that amounts spent in 2023 and 2024 dictated what would be spent in the future, testifying that 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.[509]

Mr. Coppola also addressed LVD Repetitive Outages noting that capital spending on this subprogram has been erratic, ranging from $4.1 million in 2023 to $10.7 million

---

[505] 6 Tr 4374.
[506] 6 Tr 4374.
[507] 6 Tr 4374-75.
[508] 3 Tr 2041.
[509] 3 Tr 2041.

in 2021 with meager annual spending of $4.1 million and $4.5 million in 2023 and 2024 for a program of significant importance that is enshrined in the Commission's performance standards.[510] Mr. Coppola used the forecasted capital expenditures to determine the average unit cost of $85,728 per project in the bridge period and $90,042 per project in the projected test year.[511] He went on to note that the average number of projects completed in the most recent three years was 228, at an average cost of $27,032. The average cost per unit in 2024 was $20,890. Therefore, Mr. Coppola opined that the Company's forecasted average unit costs of $85,728 for the bridge period and $90,042 for the projected test year were extremely inflated and not representative of recent actual costs. He further stated that the Company had not provided any specific justification for the large difference in the forecasted unit costs versus recent historical costs.

Based on his assessment, Mr. Coppola concluded that the average unit costs are excessive and need to be reduced to the recent actual costs. Using the three-year historical average unit cost of $27,032 from 2022 to 2024, he added inflation to arrive at a bridge period unit cost of $27,816. He then multiplied this cost by the 246 units forecasted by the Company to arrive at forecasted capital expenditures of $6,843,000 for the bridge period. For the projected test year, Mr. Coppola adjusted the bridge period unit cost by inflation to arrive at a unit cost of $28,484, which he applied to the 337 units forecasted by the Company resulting in forecasted capital expenditures of $9,599,000. As a result of his assessment, Mr. Coppola recommended that the

[510] 3 Tr 2451.
[511] 3 Tr 2451-52; Exhibit AG-1.

Commission remove $14,246,000 from the Company's capital expenditures for the bridge period and $20,745,000 from forecasted capital expenditure for the projected test year, for a total disallowance of $34,991,000.[512]

In discovery, Mr. Coppola asked the Company to identify the outage minutes in 2023 and 2024 on the circuits the Company plans to address in the bridge period and the projected test year for repetitive outages. The information provided by the Company showed that nearly half the total projects had not experienced any interruption minutes in 2023 and 2024. Mr. Coppola expressed concern with the lack of outage minutes when the Company was supposedly targeting circuits with repetitive outages and because the Company identified customer outage minutes avoided that in total exceeded the total number of outage minutes experienced by customers in 2023 or 2024.[513] As a result of this contradictory information, Mr. Coppola recommended the Commission direct the Company to provide information that showing the worst circuits with repetitive outages are being targeted and that the avoided customer interruption minutes reflect actual reductions from historical outage minutes experienced by customers on that circuit.[514]

In rebuttal, Ms. Partlan disagreed with Mr. Coppola's proposed disallowance based on a three-year historical average. Ms. Partlan explained that 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 includes

[512] 3 Tr 2452-53.
[513] 3 Tr 2453.
[514] 3 Tr 2453-54.

when scaled up.[515] She testified that 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 so projecting costs based on historical averages will not accurately reflect expected future costs. Ms. Partlan concluded stating that the Repetitive Outages subprogram is critical for achieving the Commission's CEMI-4 targets, and the Commission should therefore approve the Company's projection. If the Commission does not approve the Company's projection, she asserted it should at least adopt Mr. Boutet's position, which was significantly more reasonable.[516]

Ms. Partlan next addressed Mr. Coppola's recommendation that the Company provide "more pertinent information" about completed Repetitive Outage projects in its next rate case.[517] She stated that the Company provided information consistent with the Commission's guidance in its order in Case No. U-21585 and would comply with any updated guidance to the extent that the requested information is available. In response to Mr. Coppola's criticism that there were no outages on the circuits with projects completed in 2023 and 2024, she noted that many of those projects would have been based on outages from 2021 and 2022.[518]

In its brief, the Company reiterated the parties' testimony before first arguing that the Commission should reject Staff's proposed reduction in the work needed to reduce repetitive outages and meet Commission requirements. The Company argues it has spent over $6.3 million year-to-date on repetitive outages work and is on track to spend

[515] 3 Tr 2058.
[516] 3 Tr 2058.
[517] 3 Tr 2058.
[518] 3 Tr 2058-2059; Exhibit A-169.

over $11.2 million in 2025, demonstrating that the Company is appropriately ramping up spending as projected in this case.[519]

The Company then argues that the Commission should reject the Attorney General's proposed disallowance because the Company fully explained why unit costs are increasing in this subprogram - because the Company's CEMI performance is not improving significantly even as the Company is addressing anomalies and completing lateral fusing in other subprograms, the Company is shifting investments within the Repetitive Outages subprogram to more robust, and more costly, hardening projects such as line relocation, undergrounding, and replacing bare wire with tree resistant wire.[520]

The Company reasserts that work in Repetitive Outages is critical for the Company to achieve the Commission's CEMI-4 targets and that Mr. Coppola's proposal to base costs on historical averages will not accurately reflect the expected future work and funding needed in this subprogram.[521] The Company concludes by reiterating that it has already provided the information on Repetitive Outages results in line with the guidance in the Commission's order in Case No. U-21585.[522]

In its brief, Staff reiterates the parties' positions and argues that despite the Company's rebuttal that it is on track to reach its projected spending levels for 2025, and despite the recent underspending, investment levels are not consistent enough to suggest the Company can spend its entire projection.[523] Staff maintains its position and

---

[519] Company brief, pp. 53-54; Exhibit A-219.
[520] Company brief, p. 54.
[521] Company brief, pp. 54-55.
[522] Company brief, p. 55; Exhibit A-169.
[523] Staff brief, pp. 10-11.

asserts that the Company has spent between $242,000 and $1.1 million per month on this subprogram but is projecting to spend between $1.361 million and $1.795 million for the months of October, November, and December. Considering the foregoing, Staff continues to recommend reducing repetitive outages capital expenditures by $10,287,000.[524]

In her brief, the Attorney General relies on the parties' testimony and reiterates that spending in this program has been erratic from year to year and low in recent years even though repetitive outages has been an area of concern in prior proceedings.[525] If work performed in other areas has accomplished the same goal of reducing SAIDI and CEMI, the Attorney General argues it is unclear why the Company is now forecasting capital spending in the bridge period and projected test year that is four to six times higher than the amount spent in 2024.[526] The Attorney General reasserts that the Company has not provided justification for the significant increase in forecasted unit costs versus historical costs, which she believes is excessive.[527] Therefore, the Attorney General repeated her recommendation that the Commission disallow $14.246 million from the bridge period and $20.745 million from the projected test year.[528]

The Attorney General next addresses Mr. Coppola's concerns about the information provided by the Company to identify the outage minutes experience by customers in 2023 and 2024 on the same circuits that the Company plans to address in

[524] Staff brief, pp. 10-11; Exhibit A-219.
[525] Attorney General brief, p. 56.
[526] Attorney General brief, pp. 56-57.
[527] Attorney General brief, p. 57.
[528] Attorney General brief, pp. 57-58.

the bridge period and projected test year for repetitive outages.[529] After reiterating Mr. Coppola's testimony, the Attorney General argues that the Company's response is muddled and does not address the point made in Mr. Coppola's testimony that the forecasted reductions in Customer Interruption minutes should relate to the interruption minutes previously experienced to provide an apples-to-apples comparison and the relative benefits to customers for undertaking the proposed capital spending on Repetitive Outages.[530] As a result, the Attorney General recommends that the Commission direct the Company to provide more pertinent information that shows the worst circuits with repetitive outages that are being targeted and that the avoided customer interruption minutes reflect actual reductions from historical outage minutes experienced by customers on that circuit.[531]

The parties' reply briefs do not address this topic.

This PFD finds that the Attorney General's recommendation to disallow $34.991 million in expenditures from the bridge year and the test year is unreasonable because: 1) despite uneven spending in the last four years the Company appears poised to exceed her recommended expenditure; and 2) the Company provided some explanation regarding the increased unit cost by noting that it was shifting investment to more robust, and more costly, hardening projects such as line relocation, undergrounding, and replacing bare wire with tree resistant wire, all of which are inconsistent with the Attorney General's use of historical averages to project future costs. Therefore, this

[529] Attorney General brief, pp. 58-59.
[530] Attorney General brief, pp. 59-60.
[531] Attorney General brief, p. 59.

PFD recommends the Commission reject the Attorney General's proposed disallowances.

As to the Attorney General's recommendation that the Commission direct the Company to provide information showing the worst circuits with repetitive outages that are targeted and require that the avoided customer interruption minutes reflect actual reductions from historical outage minutes experienced by customers on that circuit, this PFD is persuaded, in part. The Company provided a list of projects with 2023 spending and outages from 2021 through May 1, 2025,[532] to show outages both before and after the expenditures; however, the Company does not fully document the expenditure of funds approved for this subprogram in U-21585, because the Company only spent $4.491 million in 2024. Nor does the Company appear to correlate the avoided customer interruption minutes with actual reductions from historical outage minutes. Therefore, this PFD recommends the Commission again direct the Company to robustly document and account for its expenditures in this subprogram in its next rate case – to include a correlation of the avoided customer interruption minutes with actual reductions from historical outage minutes.

This PFD is persuaded by Staff's recommended reductions and finds it represents a reasonable compromise between the Company's recent pattern of underspending and the recognition by the Commission in Case No. U-21585 that this subprogram is valuable to the Company's CEMI-4. In its order in Case No. U-21585, the Commission stated that it expected the Company to present a robust case in its next electric rate case to demonstrate that the dollars it approved were spent on addressing

[532] Exhibit A-169.

reliability in LVD repetitive outages.[533] However, Mr. Boutet testified that the Company reported 2024 actual spending to be $4.491 million, which represents a 54% underspend. Therefore, this PFD finds that Staff's recommended 20% disallowance to both the bridge period and test year projections for the Repetitive Outages sub-program, which equates to a $2.002 million disallowance to the 12-month bridge period, a $2.215 million disallowance to the 4-month bridge period, and a $6.068 million disallowance to the test year, is reasonable and should be adopted.

LVD Lines Rehabilitation

According to Ms. Partlan, the LVD Lines Rehabilitation subprogram includes capital repair or replacement of LVD lines equipment that has not actually failed but has been assessed to be at risk of failure in the near term. This subprogram consists of four investment categories: 1) imminent rehabilitation; 2) meter voltage anomalies; 3) subsurface transformer replacements; and 4) modem replacement program.[534] Ms. Partlan explained that subsurface transformer replacements was a new investment category in Case No. U-21585 and the meter voltage anomalies investment category has been newly defined in the instant case, based on voltage anomalies that the Company has recently begun to identify using its AMI.[535] She also noted that prior to 2024 this subprogram included an investment category called Security Assessment Repairs, which has been moved to LVD Lines Demand Failures.[536]

Ms. Partlan testified that the imminent rehabilitation category addresses issues where an actual failure has not occurred, but repair or replacement is required to

[533] March 21, 2025 order in Case No. U-21585, p. 73.
[534] 3 Tr 1968.
[535] 3 Tr 1969.
[536] 3 Tr 1969.

prevent outages and the additional expenses associated with repair following failure, as opposed to doing planned, straight-time work with lower unit costs and higher efficiency.[537] Imminent rehabilitation projects include: P3 and P4 conditions; underground cable repair; underground pad-mounted equipment relocation or replacement; underground pad-mounted equipment inspection replacement; primary or secondary voltage improvements; deteriorated conductor or equipment replacement; radio frequency interference projects; and clearance violations of conductor or equipment.[538] The Company collects data through its electric operations organization to identify issues that must be addressed by the imminent rehabilitation investment category.[539]

Next, addressing Meter Voltage Anomalies Ms. Partlan explained that the Commission's rules require that the Company provide customers with voltage that is ±5% of nominal voltage. The Company uses its AMI for continuous monitoring of voltage at the service delivery point to customers. Ms. Partlan explained that when voltage is unacceptably low, this is typically due to heavily loaded secondary and line transformers, when voltage is moderately high (between 5% and 10% greater than nominal), this is typically due to voltage regulation device issues, and when voltage is greater than 10% above nominal, this is typically due to internally faulted line transformers that are still energized. She noted that most voltage anomalies fall into the second of these categories.

---

[537] 3 Tr 1970.
[538] 3 Tr 1970-71.
[539] 3 Tr 1971.

Historically, the Company fixed voltage anomalies as they were reported by customers on a reactive basis; however, going forward the Company plans to use its AMI data to proactively address voltage compliance concerns. Therefore, Ms. Partlan stated the Company proposed to invest in correcting all three voltage anomaly causes, and would replace line transformers, mitigate regulator issues, and mitigate low voltage secondary issues.[540] The Company did not have specific projects identified for meter voltage anomalies as those projects are identified closer to the time of project execution based on up-to-date AMI data. Ms. Partlan also explained that the projected work volume for meter voltage anomalies was based on historical levels of anomalies visible in the AMI data.[541]

Turning to the Modem Replacement program, Ms. Partlan testified that this investment category supports a project to replace cellular modems that are installed inside control devices (e.g., Capacitors and Line Voltage Regulators) throughout the LVD grid because the present vendor of the Company's cellular modems announced a cessation of manufacturing in 2020 and informed the Company that it would end support in 2029. She explained that due to the large quantity, geographic locations, and physical effort needed to replace each modem, it was imperative to begin replacement efforts prior to the end of support date. Over the course of the following years, the Company would replace the total population of 5,000 cellular modems, completing approximately 800 replacements per year.[542] Ms. Partlan noted that the Company

[540] 3 Tr 1971-72.
[541] 3 Tr 1975.
[542] 3 Tr 1972.

created orders for specific modems close to the time that they were replaced, so there were no specific projects listed for this investment category.[543]

Lastly, for the Subsurface Transformer Replacement investment category, Ms. Partlan stated that this project addresses the 159 remaining original subsurface transformers in the Company's system.[544] She explained that while the transformers do not have a major impact on reliability, they posed a safety risk for Company employees and the public – they were difficult to access and repair, and they were difficult to recognize and avoid. Ms. Partlan also stated that when subsurface transformers do fail, outages lasted approximately four times longer than pad-mounted transformer failures given the difficulty of repair; subsurface transformers were also prone to leaking subterranean oil. To address these risks, Ms. Partlan stated the Company planned to replace all subsurface transformers with pad-mounted transformers by the end of 2027;[545] however; the Company only has five total subsurface transformer projects in the test year due to one large project replacing many subsurface transformers in a subdivision.[546]

Ms. Partlan testified that the Company projected LVD Lines Rehabilitation capital expenditures of $25,032,000 in the bridge period, and $27,135,000 in the test year.[547] She explained that the Company developed the costs of the projects in this subprogram considering estimated costs for materials and labor and the Company's previous

[543] 3 Tr 1975.
[544] 3 Tr 1972.
[545] 3 Tr 1973.
[546] 3 Tr 1975-76.
[547] 3 Tr 1973; Exhibit A-113.

experience conducting similar projects.[548] In addressing year-over-year variation in spending for this subprogram, Ms. Partlan stated that material delivery challenges in 2022 inhibited work in other subprograms resulting in crews completing more imminent rehabilitation work, which used materials that were more available.[549] She further explained that variation in unit cost over time was due to variations in size and complexity of work orders, as a result average unit cost does not accurately reflect the expected spend per project.[550]

Ms. York recommended an adjustment to the proposed bridge period and test year capital expenditures for the LVD Lines Rehabilitation subprogram. She asserted that the subprogram included two spending categories for which specific projects were not identified – Modem Replacement and Meter Voltage Anomalies. These two programs accounted for 37% and 54% of the bridge year and projected test year LVD Lines Rehabilitation spending, respectively, and the Company has not identified specific projects; therefore, Ms. York recommended that the projected bridge year and projected test year capital expenditures for this subprogram remain at the five-year average. This recommended adjustment removes $2.975 million from the bridge period and $5.078 million from the projected test year.[551]

In rebuttal, Ms. Partlan disagreed with Ms. York's recommendation, noting that the Company has not historically provided a list of all modem replacement projects, since they are individually small and there are 800 of them each year.[552] In Case No. U-

[548] 3 Tr 1975; Exhibits A-166, A-167.
[549] 3 Tr 1976.
[550] 3 Tr 1977-78.
[551] 6 Tr 3698.
[552] 3 Tr 2059.

21585, for example, the Company simply indicated that 800 modems would be replaced for $2,998,000 and the proposed spending was approved with no objection from any party. Meter voltage anomalies, while a new investment category in the instant case, are similar in that this category involves several hundred small individual work locations each year, and the Company has treated this similarly to modem replacements by not endeavoring to list out each individual location.[553] Ms. Partlan noted her support for the need for the modem replacement and meter voltage anomaly projects, and the basis for the projections in her direct testimony and concluded that the Commission should not remove funding for these important projects.[554]

In its brief, the Company reiterates the relevant testimony and argues that it should not be required to list hundreds of individual small projects prior to receiving funding for these necessary projects, and the Commission should reject ABATE's recommended reduction to this funding.[555]

In its brief, ABATE reiterates the relevant testimony and asserts that the Company misstates its burden when it says full lists are not practical or historically required. ABATE argues that substantiating projected spending increases requires transparent, granular evidence linking forecasts to documented need, historical trends, and rate case prudency standards. ABATE further notes that bulk programs can and should be supported by clear metrics, program scopes, failure rates, historical volumes, average unit costs, and technical justification for continued or expanded levels of investment. The absence of project lists does not alleviate the need for robust

[553] 3 Tr 2059-60.
[554] 3 Tr 2060.
[555] Company brief, p. 56.

justification and review for all investment categories, including new ones like meter voltage anomalies. For any new investment category seeking significant funding, a sound basis must be provided, such as detailed unit pricing, quantification of expected reliability benefits, and alignment with industry benchmarks.[556] ABATE concludes that the Company has failed to meet its burden to demonstrate cost recovery for these subprograms is reasonable or prudent. Based on its conclusion, ABATE asserts the Commission should only approve projected bridge year and test year capital expenditures for the entire LVD Lines Rehabilitation category at the five-year average level which removes $2.975 million from the bridge year and $5.078 million from the projected test year.[557]

The Company did not address this topic in its reply brief. In its reply brief, ABATE reiterated the arguments presented in its initial brief.[558]

This PFD is not persuaded by ABATE's argument that the Company has failed to meet its burden to demonstrate recovery is reasonable or prudent. Ms. Partlan's testimony clearly indicated why the projects were being undertaken in this subprogram, how many projects the Company plans to undertake in the bridge period and projected test year, and the expected total expenditure. Accordingly, this PFD finds the Company's request reasonable and recommends the Commission approve the Company's expenditures for this subprogram as requested.

---

[556] ABATE brief, p. 27.
[557] ABATE brief, p. 28.
[558] ABATE reply brief, p. 5.

iv. Resiliency

Ms. Partlan testified that the Resiliency subprogram is focused on improving reliability and limiting customer interruptions following major weather events, as opposed to solely improving blue-sky SAIDI (i.e., reliability primarily experienced during normal conditions).[559] She explained that resiliency subprogram investments are meant to focus on prevention, recovery, and survivability, particularly during large events. Ms. Partlan testified that preventing outages was the ideal way to reduce the number of outages to customers and reduce the amount of time spent on restoring service following a major event. Likewise, survivability increased the system's ability to withstand a storm system without failure.[560] She explained that the Company has a standalone Resiliency program because the Company has experienced an increasing frequency of high-speed wind gusts in its service territory over the past several years which, along with system deterioration, have resulted in an increase in the amount and severity of electrical outage incidents.[561]

According to Ms. Partlan, two primary investment categories are included in the Resiliency subprogram: Fractionalization and LVD Overhead to Underground conversions. The project list also includes projects for the Vulnerable Communities Resiliency Plan (VCRP) primarily discussed by Mr. Kelly, because these projects are primarily intended to increase resiliency in the targeted communities.[562]

Ms. Partlan explained that Fractionalization is the practice of segmenting LVD circuits into smaller sections with fewer customers to reduce the number of customers

[559] 3 Tr 1978.
[560] 3 Tr 1979.
[561] 3 Tr 1979.
[562] 3 Tr 1980-81.

impacted by single contingency outages and customer exposure to outages.[563] By investing in Fractionalization, the Company will be able to: 1) complete twelve new circuits at seven existing substations; 2) complete one new substation with four new circuits; and 3) complete purchase order milestone payments for one new mobile substation. She noted that the mobile substation will support construction of the additional substation projects proposed in this subprogram, avoiding customer outages that would have otherwise been required.[564]

Ms. Partlan stated that the Company targeted circuits that fall into the top tiers of circuits based upon customer count and overhead line exposure - circuits serving more than 2,000 customers or with more than 75 miles of overhead line exposure.[565] She explained that for the years 2019 to 2023 combined, circuit outages impacting more than 2,000 customers or on circuits with more than 75 miles accounted for 848,539 customer interruptions and 402,278,560 customer-outage-minutes. Accordingly, these circuits would most benefit from Fractionalization and the improved resiliency it will provide.[566]

According to Ms. Partlan, the Overhead to Underground investment category funds investments in LVD lines to completely replace certain sections of overhead LVD line with underground lines and associated equipment, but it would not fund undergrounding of services. She explained that the Company planned to underground certain LVD lines to avoid outages caused by falling trees. The Company selected lines for this project based on the following criteria: single-phase; have had at least one

[563] 3 Tr 1981.
[564] 3 Tr 1981.
[565] 3 Tr 1982.
[566] 3 Tr 1984.

outage in the last 24 months; serve between 10 and 200 customers; be operated at one of the three standard wye voltages; not be considered for another reliability project; have a load after installation of 36% or less of the ampacity of the newly installed facilities; and be located in an area that has experienced tree- or weather-related outages.[567]

She noted that since the Company's pilot was approved in Case No. U-21389, the criteria have been modified to increase the upper limit to 200 customers, the CAIDI of over 600 requirement has been removed, and rather than focus on zones with dense tree cover the focus has shifted to zones that have recently experienced significant tree- and weather-related outages.[568] Ms. Partlan further noted that the projects in the instant case were identified to have lower unit costs based on the lessons learned from the pilot.[569]

The Company is requesting recovery of resiliency capital expenditures in the amount of $21,194,000 in the bridge period, and $35,765,000 in the test year.[570] Ms. Partlan stated that projected project costs were developed considering estimated costs for materials and labor and the Company's previous experience performing similar projects.[571] The proposed Fractionalization projects will address four of the 40 highest customer count circuits, and four of the 40 highest line exposure circuits.[572] Ms. Partlan explained that the projected investment level for Overhead to Underground varies between the bridge period and the test year because the Commission did not approve

---

[567] 3 Tr 1985.
[568] 3 Tr 1986-87.
[569] 3 Tr 1987.
[570] 3 Tr 1987; Exhibit A-113.
[571] 3 Tr 1988; Exhibits A-166, A-167.
[572] 3 Tr 1989.

the Company's proposal in its last rate case because the pilot results were not yet available. With the results of the pilot now available, the Company plans to move forward with further undergrounding work beginning in the test year.[573]

According to Company witness Kelly, the Commission approved an undergrounding pilot to allow the Company to explore how undergrounding can help improve reliability for customers, comparing the benefits and costs of this work. The pilot covered approximately 10 miles of undergrounding. A Company proposal to expand on the pilot work in Case No. U-21585 was not approved because the results from the pilot were not available.[574] The pilot was particularly concerned with validating the costs of undergrounding.[575] Mr. Kelly stated the Company projected that underground conversions would cost $400,000 per line mile, but ended up with an average actual cost of approximately $422,000 per line mile of underground installed, mostly due to one particular outlier. If this outlier were discounted, the average cost for the pilot was approximately $398,000 per line mile of underground installed.[576]

Mr. Kelly testified that the Company has compared undergrounding costs to those of hardening alternatives such as installing Aerial Spacing Cable and Tree Wire, and of simply maintaining traditional vegetation management. According to Mr. Kelly, based on the utility cost test (UCT), a cost-benefit analysis framework, undergrounding has the highest cost. However, if measured by a societal cost test (SCT), undergrounding becomes the least cost option.[577] Given the long-term value provided to

---

[573] 3 Tr 1990.
[574] 3 Tr 1432.
[575] 3 Tr 1433.
[576] 3 Tr 1433.
[577] 3 Tr 1434.

customers by undergrounding, and the avoided external costs of outages resulting from the improved resiliency provided by undergrounding, the SCT should be considered as a secondary tool in evaluating the value of undergrounding.[578]

Mr. Kelly also testified that the costs were not directly comparable as they provided different means of comparison.[579] Many undergrounding projects, if in the right locations, were competitive with other non-undergrounding options, and undergrounding carried the added substantial benefits of greatly improved reliability and resiliency, plus forestry work was then no longer required.[580]

When considering the lessons learned in project selection, Mr. Kelly stated the Company was better positioned to identify economically competitive projects and expected to continue to perform underground conversions at the originally projected cost of approximately $400,000 per underground mile. Overall, Mr. Kelly testified that using the SCT, undergrounding at scale would be approximately 30% more cost effective than the alternatives of Aerial Spacer Cable and Tree Wire.[581] With an average cost of $423,000 per mile for the pilot and $400,000 per mile when at scale, he stated the Company would be able to convert overhead to underground for nearly 50% less than the $974,000 per-mile maximum cost that the Company assumed in its October 1, 2021, report in Case No. U-21122, and the Company would expect an improvement in reliability of 90% or more.[582] Based on the positive results of the pilot, the Company

[578] 3 Tr 1434-35.
[579] 3 Tr 1436.
[580] 3 Tr 1436.
[581] 3 Tr 1436-37.
[582] 3 Tr 1438.

proposed 50 miles of undergrounding in the test year, with the intent to scale the program to 400 miles per year by 2028.[583]

Turning to the VRCP, Mr. Kelly explained that the Company agreed with the other parties that in future versions of the Reliability Roadmap or future rate cases, the Company would study reliability performance and hosting capacity on circuits that overlap with EJ communities, which were defined as "census tracts that are above the 80th percentile on the MiEJScreen Overall Score."[584] Mr. Kelly presented analyses that indicated that on a systemwide basis, the Company's EJ communities have comparatively good reliability; however, there are particular EJ communities that do face reliability challenges, and given their socioeconomic vulnerabilities the Company intended to direct specific new investments to those communities to improve their reliability. Mr. Kelly testified that the VCRP is Consumers' plan to accomplish this goal, explaining that the VCRP will ensure that no EJ circuits experience worse than industry average reliability, and it would do so including MEDs to account for the actual experience of those customers. The VCRP would target EJ circuits, not EJ census tracts, because electrical geography (represented by circuits) did not always align with political geography (represented by census tracts).[585]

Mr. Kelly stated that the VCRP includes incremental investments that align with investment types that already take place in the Company's Reliability capital program, particularly in LVD Lines Reliability and Resiliency.[586] Kelly testified that the Company was not proposing to take reliability investments already in the 2023 Reliability

[583] 3 Tr 1439.
[584] 3 Tr 1443-44.
[585] 3 Tr 1444-45.
[586] 3 Tr 1445.

Roadmap and re-direct those to focus on the VCRP, but to maintain its planned reliability investments, and then perform additional targeted EJ investments.[587] Test year projects included 32.1 miles of hardening and represented a total of $30,000,000, the first tranche of investments in the plan noted above.[588] The VCRP identified all EJ circuits, particularly those with poor recent reliability performance, and simply steered direct reliability investment into those circuits.[589]

Ms. Partlan also discussed projects related to undergrounding of services and secondary improvements in DACs – noting the Company received a grant from EGLE under Section 40101(d) of the Infrastructure Investment and Jobs Act, that is intended to underground secondary in disadvantaged communities.[590] She also addressed projects related to Resiliency – MIEJ Hardening – noting that those projects represent test year work for the VCRP discussed by Company witness Kelly.[591] She concluded by detailing the benefits expected to be realized for customers related to work completed in the Resiliency subprogram and explained how the Fractionalization and Overhead to Underground projects improved resiliency.[592]

In its effort to provide competitive, affordable rates, Mr. Kelly testified that the Company was seeking federal government funding for reliability and resiliency projects through the IIJA to leverage federal funds to achieve reliability goals. If the Company is able to obtain federal funding to support distribution infrastructure investment, then the

---

[587] 3 Tr 1446.
[588] 3 Tr 1446; Exhibit A-167.
[589] 3 Tr 1447.
[590] 3 Tr 1991; Exhibits A-166, A-167.
[591] 3 Tr 1991; Exhibit A-167.
[592] 3 Tr 1991-94.

portion of the costs of that infrastructure funded by federal grants would not be passed on to customers.[593]

At the time of this filing, Mr. Kelly noted the Company had been selected for four grants related to grid reliability and resiliency, and was in the process of negotiating with the DOE on the final terms; however, it had not yet received any funding related to the grants.[594] Mr. Kelly stated that grant recipients must match a varying percentage of the funding awarded to use the grant dollars; as a result, the Company expected to match the federal funds that should be provided for the Section 40101(d) and the two Section 40101(c) grants. However, the full costs for the associated work were included in the capital exhibits, with the portion being provided by the federal government listed as negative dollar amounts.[595]

Using the 40101(c) funds, Mr. Kelly testified the Company intends to increase sectionalizing on circuits, minimizing the number of customers impacted by a single fault, and constructing new tie lines for circuits currently with no ties to neighboring circuits; ATR loops between these circuits and their new ties would also be added.[596] Additionally, the Company would use AI modeling to create value for customers in historically disadvantaged communities and in areas of high DER penetration. Data would be obtained through the deployment of 18,000 distributed AI modules on residential electric meters to analyze high volumes of data to detect and classify

[593] 3 Tr 1452.
[594] 3 Tr 1453.
[595] 3 Tr 1453-54.
[596] 3 Tr 1454.

anomalies, and improve management of distributed assets, which would be particularly valuable in locations with higher EV penetration.[597]

Using the 40101(d) funds, Mr. Kelly stated that the Company expects to perform rehabilitation work on the Athens HVD line in 2025, and on related nearby LVD circuits in 2026; as well as undergrounding of service drops and upgrades of secondary voltage lines in EJ communities.[598] While these projects were contingent on receipt of the expected funding, the project work was estimated to save 288,000 customer-outage-minutes annually, based on an estimated 80% reduction in outages on the secondary circuits and services feeding homes.[599] Mr. Kelly stated that the Company would continue to seek the use of a regulatory asset or liability to defer the revenue requirement of IIJA funding expenses above or below amounts included in rates, in accordance with the Commission's guidance in Case No. U-21227, for projects the Company has applied for but has not yet received notification of a selection decision from the federal government.[600]

Concluding the Company's discussion on the Resiliency subprogram, Ms. Partlan stated that the Company is requesting recovery of capital expenditures for the Resiliency subprogram in the amount of $21,194,000 in the bridge period, and $35,765,000 in the test year.[601] These figures break down to $15,826,000 in the bridge period and $11,647,000 in the projected test year for Fractionalization, $1,250,000 in the bridge period and $20,000,000 in the projected test year for undergrounding, and

---

[597] 3 Tr 1455.
[598] 3 Tr 1454-55.
[599] 3 Tr 1455.
[600] 3 Tr 1456.
[601] 3 Tr 1987; Exhibit A-113.

$4,118,000 in both the bridge period and the projected test year for EGLE-MIEJ Undergrounding Secondary and Services.[602]

Staff witness Boutet provided Staff's evaluation of the Company's Low Voltage Distribution system.[603] Mr. Boutet made no specific comments about the Resiliency subprogram in his discussion of the LVD subprograms.[604]

Mr. Coppola first addressed the Company's proposal to accelerate conversion of overhead lines to underground and the related capital expenditures, specifically addressing Mr. Kelly's discussion of the undergrounding pilot project from Case No. U-21389, the comparative net present value costs of undergrounding overhead lines versus other options, showing that undergrounding was the most expensive option versus other alternatives, and a comparison of costs for the four alternatives after imputing societal costs based on the ICE calculator.[605]

Mr. Coppola then testified that there were several problems with the Company's undergrounding proposal. First, the criteria outlined by Mr. Kelly have relatively low thresholds that could result in hundreds if not thousands of overhead lines that could qualify for conversion to underground. Second, the criteria did not include a benefit cost analysis (BCA) to determine whether the conversion was economic versus other options for each project. Third, the results of the pilot program showed a calculated average cost of $443,079 per comparable mile of overhead line converted to underground. Fourth, Mr. Kelly's testimony showed that even at the average cost per mile

---

[602] 3 Tr 1988.
[603] 6 Tr 4362.
[604] 6 Tr 4363-80.
[605] 3 Tr 2439.

undergrounding was not a sound economic practice.[606] Mr. Coppola then testified that the Company's proposal to undertake an expanded conversion of overhead lines to underground had not been well defined, it lacked important criteria to ensure that sound economic decisions were made, it was based on a misleading average cost per mile of overhead line to be converted to underground and should be rejected.

Mr. Coppola also assessed the EGLE-MIEJ Undergrounding projects, noting that the Company included forecasted capital expenditures for three EGLE-MIEJ Undergrounding projects in Grand Rapids, Flint, and Kalamazoo for the bridge period totaling $4,118,000 and the same amount for the projected test year. In discovery, the Company reported that the three projects were in the scoping phase, which was the preliminary phase of development with no design or other advanced work performed. Therefore, the Attorney General assessed the costs and timing of the projects as still preliminary and premature for inclusion in rate base in this rate case and recommended that the Commission remove the capital expenditures of $4,118,000 from both the bridge period and projected test year.[607]

Based on his conclusions, Mr. Coppola recommended that the Commission remove the incremental capital spending of $1,250,000 proposed by the Company for the bridge period and the $20 million for the projected test year for undergrounding.[608] Mr. Coppola also recommended the Commission remove capital expenditures of

---

[606] 3 Tr 2439-41.
[607] 3 Tr 2443.
[608] 3 Tr 2442.

$4,118,000 from both the bridge period and projected test year for the EGLE-MEIJ Undergrounding Secondary and Services.[609]

In rebuttal, Ms. Partlan disagreed and took issue with Mr. Coppola's characterization of the Company as "still struggling" with undergrounding. She asserted that 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 which allowed 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.[610]

Mr. Kelly also addressed Mr. Coppola's criticism, asserting that while undergrounding was more expensive than alternatives at-scale, it was only 2% more expensive on average, and provided a 90% reliability improvement because the threat of trees would be almost eliminated. Therefore, Mr. Kelly asserted that undergrounding still represents good value for the money.[611] In response to the Attorney General's concern about the potentially large number of overhead-line miles that could theoretically be eligible for undergrounding projects, Mr. Kelly emphasized that the Company only sought approval for 50 miles of work in the instant case. As to Mr. Coppola's assertion that a BCA was required for each project, Mr. Kelly disagreed,

---

[609] 3 Tr 2443-44.
[610] 3 Tr 2054.
[611] 3 Tr 1587.

stating the language indicated that the Commission did not expect separate benefit cost analyses for each individual project, but only one analysis covering undergrounding as a program, which the Company indicated was provided in the Company's net present value analyses.[612]

In response to Mr. Coppola's dismissal of the SCT, Mr. Kelly stated that the Company's distribution strategy was not based on identifying the maximum outage duration that customers can endure and allowing customers to experience that.[613] He stated that the Attorney General's recommendation for disallowance of both the bridge period and projected test year expenditures for undergrounding projects should be rejected based on the reasons provided above.[614]

In response to Mr. Coppola's $4,118,000 recommended disallowance for the EGLE-MIEJ Undergrounding Secondary and Services projects, Mr. Kelly indicated the Company would not contest the proposed reduction in capital expenditures for the projects but noted the disallowance would necessitate removal of the corresponding grant amounts which would reduce those negative numbers by $1,349,000 for the bridge period and $2,698,000 for the test year and put that amount back into the Company's rate base for those periods.[615]

Mr. Shaver of the CEO also reviewed the Company's update to the Reliability Roadmap focusing on the VCRP.[616] He generally supported the program, but recommended several enhancements to ensure its effectiveness, focusing on increased

---

[612] 3 Tr 1587-88.
[613] 3 Tr 1588.
[614] 3 Tr 1588.
[615] 3 Tr 1588-89.
[616] 4 Tr 3248.

transparency and long-term accountability and reporting. Specifically, Mr. Shaver recommended three things: First, Consumers should provide more detail about how the $600 million will be allocated over the 10-year horizon, including annual budgets and project priorities. Second, Consumers should outline a clear approach for tracking and reporting the plan's impacts, including how EJ circuits will be reassessed over time and how progress will be measured. Finally, Consumers should provide more detail about how regression analysis flows into overall distribution system planning.[617]

Mr. Shaver next addressed the Company's proposal to include the full first-year cost of the VCRP, $30 million, in the IRM. However, he noted it was unclear why only $30 million was planned for the first of the planned 10 years, when the full $600 million budget, allocated evenly over the full plan, would require an average of $60 million annually.[618] Further, while it was mentioned that the six new substations were already allocated under other funding mechanisms, Mr. Shaver noted that details were not provided about which substations these were, and whether the $200 million noted for fractionalization included the cost of those substations or not. Mr. Shaver recommended that the Company provide this additional detail in its rebuttal testimony.[619]

Mr. Shaver next commented on the Company's regression analysis to understand how customers in EJ communities experience grid reliability in comparison to other customers and communities. He noted that the regression analysis provided valuable insight into how reliability varies across different communities and grid characteristics. These analyses confirmed that customers in some EJ communities

---

[617] 4 Tr 3249.
[618] 4 Tr 3257.
[619] 4 Tr 3258.

experience more frequent and longer outages. Mr. Shaver asserted that it remained important to ensure that these analyses were not treated as stand-alone studies, but rather as inputs that directly informed the Company's overall spending, including areas such as O&M and storm response.[620] He additionally noted that the Company had not fully explained how the results of regression models or EJ circuit analysis flow into areas outside of capital spending.[621] Mr. Shaver recommended that Consumers provide more detail, in rebuttal, about how the regression and EJ circuit analyses are integrated into other categories—how, for example, the results influence budget allocation, O&M spending, and storm response. This would give the Commission and stakeholders confidence that the analytical tools were being systematically applied, rather than used to justify individual programs in isolation.[622] Mr. Shaver also recommended that the Company describe its approach to tracking the impact of this program using a mix of both qualitative and quantitative measures.[623] Finally, Mr. Shaver recommended that the Commission approve the VCRP.[624]

In rebuttal, Mr. Kelly noted that the Company proposed 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 more robust 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 planned to do a smaller amount of work in the first year before scaling up, as

---

[620] 4 Tr 3260.
[621] 4 Tr 3261.
[622] 4 Tr 3261.
[623] 4 Tr 3262.
[624] 4 Tr 3264.

opposed to trying to go “zero-to-60” in the first year. Mr. Kelly stated the Company’s planned glidepath for the VCRP was 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.[625] He noted the Company was unclear what information CEO sought regarding the six new substations, but offered that the substations would be new and there was no current information about them and the $200 million dollars proposed for fractionalization in the VCRP included them.[626]

CUB witness Bunch also addressed undergrounding.[627] Mr. Bunch stated that the Company did not justify the scope of its proposed undergrounding because it did not evaluate the costs and benefits of individual proposed undergrounding projects.[628] Mr. Bunch testified that half of the projected benefits of this program would be realized from a small minority of the 50 miles proposed. Given the high cost of undergrounding, Mr. Bunch opined that the Company should focus its learning and cost-curve efforts on the few projects that have encouraging cost-benefits prospects.[629]

Mr. Bunch used Consumers’ outline of the benefits that each undergrounding project was expected to yield, the yearly estimates of the average cost of interruption to its customers for 2025 through 2032, and the Company’s discount rate to calculate the net present value of avoided outages for each project through 2032 and concluded that for the entire proposed program, the eight-year present value of avoided outages for

---

[625] 3 Tr 1606.
[626] 3 Tr 1607.
[627] 6 Tr 4061.
[628] 6 Tr 4061.
[629] 6 Tr 4062.

residential customers was $689,700.[630] Mr. Bunch went on to state that the benefits were very unevenly distributed among the proposed projects with half the benefits realized from only 11.3 of the 50 miles of undergrounding proposed.[631] To determine the scope of 11.3 miles, Mr. Bunch divided the eight-year present value of avoided customer outages by the number of miles being converted for each project, sorted the present value per mile and calculated a cumulative benefit to determine at what point approximately half of the program's benefits were realized.[632] As a result of his calculations, Mr. Bunch recommended the Commission reduce the scope of the program to specific high-impact projects so that revenue requirement impacts were limited. This reduction would result in a disallowance of $15,480,000 in the test period.[633]

In rebuttal, Mr. Kelly referred to his response to Mr. Coppola on BCA. As to Mr. Bunch's calculation of the undergrounding benefits, Mr. Kelly noted that CUB's model was incomplete because it was based solely upon the present value of avoided interruption costs to customers from an undergrounding project and ignored many of the costs included in a BCA such as Return on Equity, interest, depreciation, taxes, O&M that customers would pay in return for the improved reliability benefits, and ignored the costs of alternatives to undergrounding the feeder like continued vegetation management.[634]

---

[630] 6 Tr 4062.
[631] 6 Tr 4062-63.
[632] 6 Tr 4063.
[633] 6 Tr 4065.
[634] 3 Tr 1615.

Mr. Kelly concluded that CUB misused the ICE calculator and understated the value of the project's impact on avoided interruption costs to customers given his analysis did not take into consideration the costs of alternatives.[635]

Mr. Fitzhenry, on behalf of ABATE, also testified regarding the Company's undergrounding program, noting that while the Liberty Audit recommended delaying the plan, the Company had decided to move forward with the program based on the positive results of the pilot, which demonstrated the cost-effectiveness and reliability benefits of undergrounding. Mr. Fitzhenry noted that according to the Company's own data and applying the UCT, undergrounding was the most expensive option when compared to Aerial Spacer Cable including Forestry, Tree Wire Including Forestry, and Existing Overhead Including Forestry. However, the Company also provided the results of a SCT, which demonstrated that undergrounding was the least cost option. The SCT used a lower discount rate than the UCT, which assigned more value to benefits further out in the investment lifecycle, when the benefits were more speculative. Mr. Fitzhenry expressed concern regarding the methodology deployed by the Company in both the UCT and SCT, noting that the Company had not demonstrated that undergrounding was consistently the preferred solution using both cost tests.[636]

Mr. Fitzhenry also expressed concern that the Company had issues completing specific circuits identified for undergrounding, problems that would only be exacerbated when the program was increased by 45 times its current size. In addition, if the Company changed its proposed projects from one circuit to another due to issues with

[635] 3 Tr 1615-16.
[636] 6 Tr 3727.

landowners, the benefits of undergrounding in the alternate circuit may not be as great as the benefits in the originally identified circuit, further reducing the cost-effectiveness of the program and lowering the benefits shown in the Company's UCT and SCT.[637]

Mr. Fitzhenry concluded that the Company's proposed large-scale overhead to underground conversion program should be rejected. The reliance on the societal cost test to justify the program was speculative, as it places a high value on long-term, uncertain benefits. Additionally, the lack of demonstrated ability to efficiently execute the program, coupled with the uncertainty of cost and benefits, made the current proposal imprudent. Mr. Fitzhenry recommended that the Commission follow the recommendation of the Liberty Audit and require the Company to complete and thoroughly analyze the initial pilot projects before committing to a massive capital expenditure. This recommendation would reduce the Company's test year capital expenditures by $20 million.[638]

In rebuttal, Mr. Kelly testified that Mr. Fitzhenry never clearly stated what his concerns were, making it difficult to effectively rebut his position.[639] However, he countered that undergrounding is only 2% more expensive than alternatives and is expected to provide at least a 90% reliability improvement. Mr. Kelly further asserted that Mr. Fitzhenry's only apparent criticism of the SCT was that it was "speculative," and he did not provide any support for why the SCT was inappropriate to use.[640] Mr. Kelly also disagreed with Mr. Fitzhenry's comments on the undergrounding pilot, asserting that a hallmark of a successful organization was that it could make adjustments and

[637] 6 Tr 3728.
[638] 6 Tr 3728-29.
[639] 3 Tr 1599-1600.
[640] 3 Tr 1600.

adapt as challenges arise. He also stated that the Company only proposed scaling to 50 miles in this proceeding.[641]

In its brief, the Company relies on the parties' testimony and argues that the projected Resiliency sub-program spending will reduce the number of outages on the LVD system and will also provide more time for line workers to complete other restoration work, resulting in quicker restoration overall. The Company also addresses its proposal for an additional $30 million in test year funding for the VCRP to make strategic investments on EJ circuits with a goal of ensuring that every EJ circuit in the Company's service territory has SAIDI, including MEDs, that is in the second Institute of Electrical and Electronics Engineers (IEEE) quartile or better.[642]

In response to Mr. Coppola's criticism of the undergrounding proposal, the Company argues that it is not struggling to develop its undergrounding approach, but has demonstrated that undergrounding provides cost-effective reliability benefits.[643] Based on lessons learned in the undergrounding pilot, the Company argues that undergrounding is, at worst, comparable to other alternatives and it provides a 90% or greater improvement in reliability.[644] Therefore, the Commission should reject Mr. Coppola's removal of additional funding for undergrounding work in the bridge period and test year.[645]

In response to ABATE's recommendation to remove $20 million in the test year funding for undergrounding, the Company rebuts each point rejecting ABATE's

---

[641] 3 Tr 1601.
[642] Company brief, p. 57.
[643] Company brief, p. 58.
[644] Company brief, p. 59
[645] Company brief, p. 60.

assertion that the pilot was unsuccessful and acknowledging that it faced challenges that required it to adapt, which demonstrates its agility.[646]

The Company then addresses Mr. Bunch's recommendation to reduce the scope of the undergrounding program.[647] Relying on testimony, the Company asserts that Mr. Bunch's analysis fails to recognize that the Company will still need to invest in the maintenance of equipment or vegetation on the feeder and in crew time and materials to restore customers when an outage occurs. Each of the Company's planned undergrounding projects will provide avoided customer outage minutes; therefore, the Commission should approve the requested funding for these projects to allow the Company to move forward with improving reliability for these customers.[648]

In response to the Attorney General's recommended removal of $4.118 million in the bridge period and the test year for the EGLE-MIEJ Undergrounding projects based on his contention that the projects are still preliminary, Consumers agreed not to contest this proposal but noted if these expenditures were removed from the test year, then the corresponding grant amounts should also be removed from the total, reducing those negative numbers by $1.349 million in the bridge period and $2.698 million in the test year.[649]

In response to CEO witness Shaver's testimony, the Company notes that it responded to Mr. Shaver in rebuttal regarding the spending plan, the regression and EJ circuit analyses.[650] The Company agrees that Mr. Shaver's proposals for assessing the

---

[646] Company brief, pp. 60-61.
[647] Company brief, p. 61.
[648] Company brief, pp. 61-62.
[649] Company brief, p. 62.
[650] Company brief, pp. 62-63.

impacts of the VCRP generally seem reasonable; however, point out that 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 data to begin to draw conclusions.[651] Staff did not address the Resiliency subprogram in its brief.

In her brief, the Attorney General addresses undergrounding and the EGLE-MIEJ program. First, the Attorney General examines the undergrounding, beginning by addressing the updated selection criteria and opining that the changes indicate the Company is still searching for an effect approach to justify the program.[652] The Attorney General then restates that there are several problems with the Company's proposal: 1) the criteria are relatively low thresholds that could result in hundreds of qualifying lines; 2) the criteria do not include a BCA; 3) the results of the pilot program show a calculated average cost of $443,079 per comparable mile but 63% had a cost 20% to 126% above average; 4) even at the average cost per mile undergrounding is not a sound economic practice.[653] She also pointed out that the Commission requested additional evidence, including a BCA, to fully evaluate the proposed undergrounding. Based on her evaluation, the Attorney General asserts that the Company's proposal to undertake an expanded conversion of overhead lines to underground has not been well defined, lacks important criteria to ensure that sound economic decisions are made, it was based on a misleading average cost per mile of overhead line to be converted to underground and should be rejected. Therefore, the Attorney General recommends that the Commission

[651] Company brief, p. 63.
[652] Attorney General brief, pp. 61-62.
[653] Attorney General brief, pp. 62-64.

remove the incremental capital spending of $1,250,000 proposed by the Company for the bridge period and the $20 million for the projected test year.[654]

Turning to the EGLE-MIEJ undergrounding projects the Attorney General recommends that the Commission remove the capital expenditures of $4,118,000 from both the bridge period and projected test year.[655] As noted above, Consumers concurs with this recommendation.

Based on the above assessment of the Resiliency subprogram, the Attorney General recommends that the Commission remove $5,368,000 for the bridge period and $24,118,000 for the projected test year from the Company's forecasted capital expenditures.[656]

In its brief, CEO relies on and reviews the parties' testimony.[657] CEO restates Mr. Shaver's recommendations to ensure the VCRP delivers the results that Consumers anticipates: First, that the Company should reassess annually which circuits are included in the plan. Second, that the Company identify a set of "peer" circuits as a control group to compare reliability performance to. Finally, Witness Shaver recommended that the Company periodically survey its customers to understand how their experience of the grid changed over time based on the implementation of the Plan.[658] CEO concludes recommending that the Commission approve the Company's

[654] Attorney General brief, p. 65.
[655] Attorney General brief, p. 66.
[656] Attorney General brief, p. 66.
[657] CEO brief, pp. 19-23.
[658] CEO brief, p. 23.

spending allocated to the Vulnerable Communities Resilience Plan in this case with the reporting requirements recommended by CEO.[659]

In its brief, MNSC relies on the parties' testimony and argues that most of the expected benefits from undergrounding can be realized from a small minority of Consumers' proposed projects. Mr. Bunch recommends that the Commission should, in test year 2026, limit the scope of Consumers' undergrounding program to projects with only the highest reliability impacts. MNSC then asserts that the costs and benefits of individual undergrounding projects are highly variable and cannot be easily generalized.[660] MNSC argues that the Company did not sufficiently justify its proposals to increase undergrounding projects in the test year and beyond.[661] MNSC argues that the Company's argument that a single BCA is sufficient is not correct; rather, while the Commission said a BCA is necessary, they did not say or suggest a single BCA would be sufficient – asserting the surrounding context indicates that the Commission did not mean a single programmatic BCA would suffice.[662] Without individual BCAs for individual undergrounding projects, it is impossible to evaluate proposed undergrounding against other reliability programs on an apples-to-apples basis.[663] MNSC also argues that the Company's critique of Mr. Bunch's analysis is not persuasive.[664] Therefore, MNSC recommends a reduction in scale of the Company's

[659] CEO brief, p. 26.
[660] MNSC brief, pp. 6-7.
[661] MNSC brief, p. 8.
[662] MNSC brief, p. 9.
[663] MNSC brief, p. 10.
[664] MNSC brief, pp. 11-12.

test year undergrounding program, approving only those 11.3 miles of high-impact projects identified by Mr. Bunch, saving ratepayers $15,480,000.[665]

Neither the Company, Staff, nor the Attorney General addressed this topic in their reply briefs. In its reply brief, ABATE relied on its initial briefing and asserted the Commission should reject the Company's proposal to greatly expand the undergrounding program.[666]

In its reply brief, MNSC argues that the Commission should not approve expensive underground conversions simply because it will provide avoided customer outage minutes.[667] Exhibit A-167 showed – and MNSC's initial brief highlighted – that the reliability benefits for individual projects range from 22,000 to 436,500 customer outage minutes avoided.[668] The Company has the burden to produce enough information for the Commission to "fully evaluate the proposed undergrounding" projects against one another and against alternatives.[669] MNSC reiterates Mr. Bunch's testimony comparing the relative impacts of Consumers' projects and showing that over half of expected residential customer benefits can be "realized from only 11.3 of the 50 miles of undergrounding proposed" and at a fraction (23%) of the proposed cost. MNSC relies on that information to assert that the Commission should prioritize the highest impact projects, shrink the size of the undergrounding program, and save ratepayers $15,480,000 relative to the Company's initial proposal.[670]

---

[665] MNSC brief, p. 12-13.
[666] ABATE reply brief, p. 5.
[667] MNSC reply brief, p. 1.
[668] MNSC reply brief, pp. 1-2.
[669] MNSC reply brief, p. 2.
[670] MNSC reply brief, p. 2.

In the absence of comments or objections from any party regarding the Company's forecasted capital expenditures for Fractionalization, this PFD recommends the Commission approve the Company's requested expenditures for Fractionalization, as stated.

As for the Attorney General's recommendation on undergrounding, echoed by MNSC and ABATE, this PFD agrees with MNSC's recommendation to disallow $15,480,000 million for the projected test year for underground conversions. The Commission's disapproval of the Company's proposed undergrounding in Case No. U-21585 was based, in part, on the incomplete status of the pilot; however, the pilot has been completed (more or less), with a BCA provided and adjustments to selection criteria made because of lessons learned. Nevertheless, the concerns raised by MNSC, especially regarding the need for individual BCA's for each undergrounding project, and the fact that most outage minutes avoided are confined to only a fraction of the miles proposed for the program, are persuasive.

The Company agreed not to contest the Attorney General's recommendation to remove the funding for the EGLE-MIEJ Undergrounding projects. Therefore, this PFD recommends the Commission remove the associated funding and grant amounts from the bridge period and the projected test year.

This PFD also concurs with the CEO recommendations to provide more detail about how the funding for the VCRP will be allocated over the 10-year horizon, including annual budgets and project priorities, the need for a clear approach for tracking and reporting the plan's impacts, including how EJ circuits will be reassessed over time and

how progress will be measured.[671] This PFD also concurs with CEO's recommendation that the Company describe its approach to tracking the impact of this program using a mix of both qualitative and quantitative measures.[672] Therefore, this PFD recommends the Commission direct the Company to begin providing this information in its next rate case or DSP filing, whichever happens first.

c. LVD Capacity

i. LVD Lines Capacity

According to Ms. Partlan, the LVD Lines Capacity subprogram is intended to address and reduce overload risk on components of the LVD lines system.[673] The LVD Lines Capacity subprogram consists of investments in equipment upgrades and lines capacity projects associated with substation projects.[674] Ms. Partlan testified that the Company upgraded or replaced overloaded lines and equipment to reduce reliability and safety risks, including equipment failure. Fixing overload risks on the LVD system also better positions the system to accommodate future growth of EV charging, heating electrification, and other customer adoptions of new technologies.[675] The Company projected LVD Lines Capacity capital expenditures of $28,580,000 in the bridge period, and $54,911,000 in the test year.[676] The projected expenditures are directly tied to the LVD Overload Risk Reduction plan outlined in the Reliability Roadmap which is

[671] 4 Tr 3249.
[672] 4 Tr 3262.
[673] 3 Tr 1995.
[674] 3 Tr 1995.
[675] 3 Tr 1996.
[676] 3 Tr 2002; Exhibit A-113.

intended to address all components overloaded beyond 100% of their rating in order to eliminate overload-caused outages on the LVD system.[677]

Ms. Partlan testified that the increase in spending in the bridge period is aligned with what the Commission approved in Case No. U-21585.[678] She noted that the investments made to upgrade overloaded assets and alleviate voltage issues increased the longevity of the equipment and prevented service issues and interruptions to customers while improving employee and public safety.[679] Ms. Partlan stated that average unit cost was not a good measure of spend to predict the cost of an individual project in this subprogram, because there is a wide variance among work required, ranging from $2,000 for a protective device upgrade to $2,000,000 for a multi-mile voltage conversion project.[680]

Mr. Boutet discussed the Company's proposal for the LVD Lines Capacity subprogram to spend $21.365 million in the bridge period to complete 125 units of work, and $53.103 million in the test year to complete 278 units of work in the Overloaded Equipment investment category.[681] While Mr. Boutet recommended that the Commission approve the Company's proposed bridge period Overload Equipment investment as consistent with the number of projects recently approved in Case No. U-21585, he did not support the proposed expenditures for the projected test year saying that the Company did not demonstrate that these expenditures are reasonable and prudent. Further, he explained skepticism that the Company will be able to effectively

[677] 3 Tr 1997.
[678] 3 Tr 2002.
[679] 3 Tr 2004.
[680] 3 Tr 2004.
[681] 6 Tr 4370.

scale up spending given current year-to-date spending trends.[682] He reasoned that the Company's proposed 278 projects in the test year represent a three-fold increase in annual work projects between the bridge period and the test year but the Company's spending between January and June 2025 demonstrates a trajectory of spending only 34% of its projection as it has only spent $3.595 million on its LVD Lines Capacity sub-program of its projected $21.435 million in expenditures for 2025.[683] Therefore, Staff recommended the Commission approve the Company's proposed bridge year funding but recommended that the Commission disallow approximately $18.72 million from the projected test year for this investment category, based on a project-count reduction from the proposed 278 projects to 180 projects.[684]

In rebuttal, Ms. Partlan revisited Staff's recommendations and stated that the Company would not oppose Mr. Boutet's recommendations regarding the LVD Lines Capacity sub-program projected expenditures in this case.[685]

Mr. Coppola also addressed the forecasted capital expenditures for the overloaded equipment upgrades, noting that spending increased from less than $10 million annually to nearly $30 million in the bridge period and $55 million in the projected test year.[686] Mr. Coppola asserted that the Company's representation that spending would occur across the board for all overload percentage did not match the Company's categorization of risk.[687] During discovery, Mr. Coppola requested the Company identify the number of circuits by risk level and capital spending, which showed 83 projects with

---

[682] 6 Tr 4370-4371.
[683] 6 Tr 4370-71.
[684] 6 Tr 4371.
[685] 3 Tr 2039.
[686] 3 Tr 2444.
[687] 3 Tr 2445.

140% overload category and related spending of $15,989,000, 41 projects with overload of less than 140% and related spending of $5,375,000, and 155 circuits in less risky categories for total forecasted capital spending of $40,911,000, 115 circuits of which had an overload condition of 119% or less.[688] Finding that the spending priorities were inconsistent with its categorization of risk and not adequately supported, Mr. Coppola recommended the Commission remove $5,375,000 of capital expenditures for the bridge period and $40,911,000 for the projected test year that was directed at the lower risk projects with overload of less than 140%.[689]

In rebuttal a, Ms. Partlan disagreed with the suggestion that only circuits with over 140% overload were circuits that should be addressed and that any overload lower than that level was "less risky" and therefore investments directed at them were unnecessary and could be deferred.[690] Ms. Partlan asserted that Mr. Coppola's recommendation reflected an unacceptable tolerance for allowing assets to operate well beyond manufacturer specifications for extended durations and treated all assets as though they had equal risk levels at a given overload percentage.[691] Ms. Partlan concluded that Mr. Coppola's proposed disallowances should not be accepted by the Commission, which should instead accept the proposal of Mr. Boutet.[692]

In its brief, the Company reviews the applicable testimony and notes that the Company's bridge period expenditures are in line with the spending that the Commission approved in Case No. U-21585 and that it would be unreasonable to

---

[688] 3 Tr 2445.
[689] 3 Tr 2446.
[690] 3 Tr 2065.
[691] 3 Tr 2065.
[692] 3 Tr 2056.

disallow this approved amount.[693] The Company also asserts that the Commission should reject the Attorney General's risky proposal to not address system overloads until they are at the highest risk level and ignore assets overloaded at less than 140% because it would present a significant risk to reliability and public safety.[694]

This PFD finds that the Attorney General's recommendation to disallow expenditures in both the bridge year and the test year which would address system overloads below the highest risk level does not provide a sufficient basis for treating risk level classifications differently as she has provided no evidence that removing attention to lower risk overloads will be sufficient to protect safety or assure reliability. This PFD is persuaded by the Company's position that focusing only on overloads at the highest risk level presents too great a risk to reliability and is not the most prudent way to approach either the risk or efforts to improve reliability and safety. This PFD, thus, recommends the Commission reject the Attorney General's proposed disallowances. Because the Company did not object to Staff's recommendation for approval of the proposed bridge year funding and disallowance of approximately $18.72 million from the test year for this investment category, based on a project-count reduction from the proposed 278 projects to 180 projects, this PFD finds the Company's bridge year projection reasonable and consistent with the Commission's order in Case No. U-21585; however, the test year projection appears overly ambitious considering the Company's current spending patterns. Therefore, the PFD finds that Staff's recommended disallowance should be adopted.

---

[693] Company brief, p. 64.
[694] Company brief, p. 65.

ii. LVD New Business Capacity

Ms. Partlan testified that the LVD New Business Capacity subprogram includes equipment and lines that need to be added or upgraded for new customers or to maintain adequate service to existing customers when they increase their load beyond existing capacity. This work is driven by customer requests, so the Company does not plan or prioritize projects far in advance, nor does the Company have much latitude on whether to delay or defer these new business capacity projects.[695] Ms. Partlan stated that work in the LVD New Business Capacity subprogram ensures the reliable distribution of electricity to customers by preventing overloads on the system that can cause outages and poor voltage service. The Company is projecting LVD New Business Capacity capital expenditures of $38,180,000 in the bridge period, and $30,130,000 in the test year.[696]

Ms. York testified that because actual spending in these categories is driven by customer requests, which are unknown at this time, it would be more reasonable and prudent to limit the projected investment in this category to the five-year average actual spend for both the Bridge Period and Test Year. This adjustment removes $11.958 million from the bridge period and $3.908 million from the test year.[697]

In rebuttal, Ms. Partlan disagreed with Ms. York's recommended adjustment. In support of the Company's projected expenditures in this subprogram, Ms. Partlan provided several justifications.[698] First, in past cases, the Company has provided similar levels of detail and received full recovery following no objection from any parties.

[695] 3 Tr 2004-05.
[696] 3 Tr 2006.
[697] 6 Tr 3699.
[698] 3 Tr 2060-61.

Second, 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.[699] Finally, the Company's year-to-date spending through September has been $18,881,217, which, if continued at the same rate, would result in spending more than Ms. York's proposal. Ms. Partlan asserted that these justifications highlight the unreasonableness of Ms. York's recommendation.[700]

The parties' briefs rely on their respective witness's testimony. The Company reiterates that recent actual spending in LVD New Business Capacity shows that using a five-year average is not a reasonable projection of test year costs, pointing out that year-to-date spending is on track to exceed ABATE's proposal for the bridge period, and urging the Commission to reject this recommended disallowance.[701] Whereas ABATE asserts that the Company's projection is not adequately supported, is highly speculative, and should be disallowed.[702] Acknowledging that spending is customer-driven and largely uncertain, ABATE points to the limited work identified in the Company's filing and to historic spending levels (but discounting two-years of above-average spending) to justify its recommendation to set spending for this sub-program to the five-year average.

This PFD does not find ABATE's arguments on this issue persuasive. This PFD agrees with Ms. Partlan that the Company is on track to exceed ABATE's proposed expenditure. Further, the evidence demonstrates that the Company's year-to-date spending supports Ms. Partlan's assertion. Additionally, this PFD finds that the five-year

[699] 3 Tr 2061.
[700] 3 Tr 2061-62.
[701] Company brief, pp. 65-66.
[702] ABATE brief, p. 32.

historical average reflects steady escalation of spending in this subprogram consistent with the Company's projected expenditures.[703] Therefore, this PFD recommends that the Commission reject ABATE's proposal and approve expenditures in this subprogram as requested by the Company.

iii. Conservation Voltage Reduction

Ms. Partlan testified that CVR is the capability to optimize service-point—or customer meter voltages—to reduce energy demand without requiring active participation or specific investment by customers.[704] CVR technology allows for continuous monitoring and automatic adjustment of these settings to achieve optimal voltage and load reduction while staying within the regulatory requirements. Ms. Partlan stated that this subprogram of the Capacity Program funds capital projects necessary for implementing the Company's overall CVR plan that is included in the IRP.[705] The projects install and upgrade equipment to ensure that the targeted LVD circuits can enable CVR without providing voltage to customers outside the allowable range.[706]

Ms. Partlan testified that the Company identified CVR projects primarily based on customer types and circuits with smart grid capabilities since CVR is more effective on residential load types and less capital investment is needed to enable CVR on circuits that have already deployed upgrades to substation and line equipment. She stated that the Company has identified 75 circuits for the bridge period and 85 circuits for the test year.[707] The Company is projecting CVR capital expenditures of $5,586,000 for the

---

[703] Exhibit A-113.
[704] 3 Tr 2010.
[705] 3 Tr 2010.
[706] 3 Tr 2010.
[707] 3 Tr 2012.

bridge period, and $4,070,000 in the projected test year.[708] Ms. Partlan also noted that average unit cost was not a good measure of spend to predict the cost of an individual project in this subprogram as there is a wide variance among work required ranging from $5,000 to as high as $400,000 per project.[709]

Mr. Boutet reviewed the Company's projected expenditures for the CVR subprogram and explained that Staff did not support the proposed expenditures. He explained that there is a clear trend showing Consumers underspending the allotted funds for this program – stating that the Company underspent its 2023 projections by 57% and its 2024 projections by 42%.[710] Further, he stated that the Company made errors in recent reporting of benefits related to the CVR program for achieved cumulative peak MW reduction.[711] To the Company's benefit, Mr. Boutet stated it was also evident that the Company overperformed its projections for cumulative MWh reduction in 2024, which caused Staff to opine that the peak MW reduction metric benefit was over-projected by a larger margin than the cumulative MWh reduction metric benefit was under-projected, meaning that weighing the two metrics equally would suggest the Company is ultimately not projecting its costs and benefits properly.[712]

Considering the above, Mr. Boutet stated that Staff recommends disallowances to the CVR sub-program such that the funding would be reset to the Company's most recent five-year historic average plus inflation. The current five-year average for the

---

[708] 3 Tr 2013.
[709] 3 Tr 2014.
[710] 6 Tr 4368.
[711] 6 Tr 4368-69; Exhibit S-13.3.
[712] 6 Tr 4369.

CVR sub-program is $3.166 million.[713] Utilizing the Company sponsored inflation rates of 2.1% for 2025, 2.4% for 2026, and 2.4% for 2027 results in a 12-month bridge period projected expenditure of approximately $3.232 million, a four-month bridge period projected expenditure of approximately $1.103 million, and a test year projected expenditure of approximately $3.336 million.[714] The associated disallowances range between 7.5% and 26%, which are notably lower than the percentages by which the Company has underspent in the most recent years, and are reasonable given that they align with the Company's five-year historic average spending.[715]

In rebuttal, Ms. Partlan testified that the Company will not oppose Staff's recommendation regarding the CVR subprogram projected expenditures in this case.[716]

Noting the Company's concurrence with Staff's recommendation, this PFD finds this issue is moot, and Staff's adjustment, agreed to by Consumers, should be adopted.

iv. LVD Metering and Transformers

According to Ms. Partlan, the LVD Metering subprogram supplies meters and associated equipment including meter sockets, metering transformers, and meter testing equipment. She testified that LVD Metering expenditures were historically allocated between the New Business and Demand Failures programs, but LVD Metering has always operated through a single purchase plan, and in this filing the Company combined them into a single subprogram under Demand Failures. Meter Sockets and Electric Capital Meter Test Equipment costs are allocated across the total

[713] 6 Tr 4369; Exhibit A-113.
[714] 6 Tr 4369; Exhibit S-13.10.
[715] 6 Tr 4369.
[716] 3 Tr 2038.

meter and metering transformer units to determine the overall cost per unit for this subprogram.[717]

The Company projected LVD Metering New Business of 27,634 units and $18,050,400 capital expenditures in the bridge period and 20,726 units and $15,108,000 capital expenditures in the test year, with LVD Metering Demand Failures projected at 41,451 units and $27,075,600 capital expenditure in the bridge period and 31,088 units and $22,662,000 capital expenditure in the test year.[718] For total projected capital expenditures of $45,126,000 for the bridge period and $37,770,000 for the test year.[719]

No party opposed the Company's proposed investment; thus, this PFD finds the Company's requested expenditure reasonable and prudent and recommends the Commission approve it, as requested.

Turning to the LVD Transformers subprogram Ms. Partlan explained that this investment category supplies the distribution transformers that provide the means to supply electricity to customers at an acceptable voltage, with the number of transformers needed driven primarily by activity in the LVD Lines New Business subprogram. The Company projected LVD Transformers capital expenditures of $227,963,000 in the bridge period and $207,782,000 in the test year.[720]

According to Ms. Partlan, the Company developed its distribution transformer purchase plan by estimating the total number of transformers needed, based on historical actual data, with potential fluctuation in individual years based on lines

[717] 3 Tr 2015.
[718] 3 Tr 2016; Exhibit A-113.
[719] Exhibit A-113.
[720] 3 Tr 2023.

projects in the Company's reactive spending programs.[721] She further testified that in 2025 and beyond the Company expected purchases of overhead transformers will remain generally level, but the Company is planning for a continued significant increase in purchases of pad-mounted transformers tied to increased undergrounding work for both new service connections and primary and secondary circuits; for general new business work; and for the need to support customers adopting EVs.[722]

Mr. Coppola testified that the volume increases were from new purchases of pad-mounted transformers tied to increased undergrounding work for new services, primary and secondary circuits likely related to undergrounding overhead lines, and EVs.[723] In response to discovery, Mr. Coppola explained that Consumers showed that forecasted capital expenditures for the bridge period and projected test year included large increases in 1-phase and 3-phase pad-mounted transformers from 2024 to 2027. According to Mr. Coppola:

> The forecast for the 1-phase pad-mount transformers shows an increase from 2,876 units in 2024 to 7,469 units in 2027. This total increase over the three-year period reflects an increase of 63% in 2025 over 2024 and 34% in 2026. These increases are on top of a 48% increase in the number of units in 2023 over 2022 and another 24% increase in 2024 over 2023. The forecast for the 3-phase pad-mount transformers shows similar high increase of 64% in 2025 over 2024 followed by a decrease of 20% in 2026 and an increase of 60% in 2027. The increase in units from 2023 to 2024 was 32%.[724]

Mr. Coppola then asserted that the increases for 2025 through 2027 were excessive and not supported by any calculations or other evidence.[725]

---

[721] 3 Tr 2024.
[722] 3 Tr 2024.
[723] 3 Tr 2446.
[724] 3 Tr 2447.
[725] 3 Tr 2447.

Consistent with this testimony, Mr. Coppola calculated an appropriate number of 1-phase and 3-phase pad-mounted transformers for the bridge period and projected test year. For 1-phase transformers his calculation resulted in a recommended disallowance of $9,791,000 from the bridge period[726] and $11,777,000 from the projected test year.[727] For 3-phase transformers, his calculation resulted a recommended disallowance of $5,514,000 in the bridge year, and $3,005,000 in the test year.[728] In total, Mr. Coppola recommended the Commission remove $15,305,000 for the bridge period and $14,782,000 for the projected test year from the Company's forecasted capital expenditures for LVD Transformers.[729]

In rebuttal, Ms. Partlan testified that the Company did not agree with Mr. Coppola's recommendation to eliminate the Company's overhead under-grounding work – and if the overhead under-grounding plan is approved, then the transformers will be needed. She noted that pad-mounted transformer purchases were increasing prior to the initiation of overhead under-grounding work, indicating that other factors such as new business work are driving growth in transformer needs with this work further increasing growth. As a result, she asserted the Commission should approve the Company's projection.[730]

Ms. York also took issue with the Company's projected capital expenditures in the LVD Transformer subprogram, noting that the projects represented a dramatic

[726] 3 Tr 2448; Exhibit AG-9.
[727] 3 Tr 2449; Exhibit AG-9.
[728] 3 Tr 2450; Exhibit AG-9.
[729] 3 Tr 2450.
[730] 3 Tr 2057.

increase relative to the five-year historical average.[731] According to Ms. York, there was significant uncertainty surrounding investment tied to new business and electric vehicle adoption. She also noted that the Company's desire to restock inventory did not mean transformers would become used and useful to customers during the bridge period and projected test year.[732] As a result, Ms. York asserted that a more reasonable and prudent approach to projecting capital expenditure would be to use the 2024 actual amounts as the projection, which both captured the 2024 increase in spend and recognized the uncertainty she described. Therefore, she recommended reducing the Company's projected capital expenditure by $105.077 million and $84.896 million for the bridge period and test year, respectively.[733]

In rebuttal, Ms. Partlan disagreed with Ms. York's characterization of the projected growth as uncertain. She asserted that the growth in overall LVD Transformers spending was driven primarily by growth in purchases of 1-phase and 3-phase pad-mounted transformers, which was driven, in turn, by undergrounding work, by general new business activity, and by projected "EV adoption. Undergrounding work is not uncertain; the Company has a clear plan for undergrounding backed by many specific projects.[734] Ms. Partlan further asserted that the Company's basis for growth in LVD Transformers was well-substantiated.

Ms. Partlan next addressed Ms. York's statement alluding to building up inventory. She explained that due to acute supply chain disruptions in the transformer industry during the early 2020s, utilities experienced significant backlogs in procuring

[731] 6 Tr 3699-3700.
[732] 6 Tr 3700.
[733] 6 Tr 3700.
[734] 3 Tr 2062.

essential equipment. In response to the backlogs, the Company fundamentally altered its procurement strategy and is now compelled to place full-year orders upfront to secure appropriate quantities, as well as hedge against ongoing supply risks.[735]

Finally, Ms. Partlan stated that the Company's year-to-date spending in the LVD Transformers subprogram showed that it was on pace to exceed the 2025 bridge period projection.[736]

In its brief, the Company reiterates Ms. Partlan's testimony before addressing the recommendations of the Attorney General and ABATE.[737] First, the Company asserts that the Attorney General's proposed disallowance relies in part on her recommendation that the Commission reject the Company's proposed under-grounding work. In response, the Company asserts that the Commission should reject the Attorney General's recommendation to remove the under-grounding work and the reduction in projected pad-mounted transformer purchases.[738] The Company argues that need for transformers has already increased and it will need the transformers even more if the under-grounding is approved. Therefore, the Company asserts the Commission should reject the Attorney General's proposed reduction to ensure that the Company has sufficient pad-mounted transformers to meet customer needs.[739]

Second, the Company addresses Ms. York's argument that there is uncertainty around investing in transformers and restocking inventory should not be included in

---

[735] 3 Tr 2063.
[736] 3 Tr 2063; Exhibit A-219.
[737] Company brief, p. 67.
[738] Company brief, p. 68.
[739] Company brief, p. 68.

expenditures.[740] In response, the Company reiterates Ms. Partlan's testimony pointing out that: 1) undergrounding is not uncertain, 2) new business is resulting in increased rates of transformer need, and 3) the transformation of the Company's procurement strategy in response to significant backlogs changed expenditures. Accordingly, the Company argues the Commission should reject ABATE's proposed reduction because it does not account for the increasing needs for pad-mounted transformers.[741]

In her brief, the Attorney General relies on and reiterates the parties' testimony and recommends that the Commission remove $15,305,000 for the bridge period and $14,782,000 for the projected test year from the Company's forecasted capital expenditures.[742]

In its brief, ABATE relies on the parties' testimony and argues that the Company's planned expenses are highly inexact and cannot serve as a basis for determining these cost projections or cost recovery related thereto is reasonable or prudent. ABATE also argues that investments in new business and support for EV adoption are highly uncertain and increased pad-mounted transformer purchases do not correlate with customer benefits or their actual use. ABATE further states that the Company should be required to provide clearer documentation differentiating between purchases for operational need and inventory hedging.[743] Because the forecast is speculative, ABATE asserts that conservative budgeting should apply and large year-over-year capital increases should be supported by a clear pipeline of identified projects, purchase orders, and demonstrable need, consistent with the Company's

[740] Company brief, p. 68.
[741] Company brief, pp. 68-9.
[742] Attorney General brief, pp. 69-73.
[743] ABATE brief, pp. 33-34.

burden as described by the Commission.[744] A more reasonable and prudent approach to projecting capital expenditures for LVD Transformers would thus be to use 2024 actual capital expenditure amounts for both the Bridge Period and Test Year – thus balancing reliability with fiscal responsibility – reducing the Company's projected capital expenditures by $105.077 million and $24.292 million for the Bridge Period and Test Year, respectively.[745]

Neither the Company nor the Attorney General addressed this topic in their reply briefs. In its reply, ABATE relies on the parties' testimony and initial briefs and reiterates its argument that because the Company's projections are based on an estimated number of transformers needed and inexact and inadequately supported assumptions, the Commission should limit cost recovery to 2024 actual amounts.[746]

This PFD is not entirely persuaded by ABATE's arguments for significant reductions to the LVD Transformers spending category based on historical data; however, this PFD agrees that to some degree, the Company's projection, which represents a substantial increase over past investments is speculative and not sufficiently supported. Therefore, this PFD recommends that the Commission approve the Attorney General's adjustments of $15,305,000 for the bridge period and $14,782,000 for the projected test year, amounts that represent disallowances of approximately seven percent of the Company's request.

---

[744] ABATE brief, p. 34.
[745] ABATE brief, p. 35.
[746] ABATE reply brief, p. 6.

d. Grid Modernization

Mr. McPhail provided an overview of the Company's Grid Automation plan and the proposed capital expenditures for plan implementation.[747] He stated that Grid Automation is a fundamental part of the electric distribution business and a foundational piece of the Company's Reliability Roadmap.[748] He stated that by enhancing the ability for smart meters, sensors, and automation devices to work together to monitor, isolate, and automatically respond to interruptions more effectively, Grid Automation investments result in reliability, resiliency, and efficiency benefits.[749] He added that customers also benefit from these investments through improved power quality, grid safety, and affordability.[750] Mr. McPhail further testified that the Company's goal is to identify and incorporate proven, updated grid technologies into its standard deployment programs, and he described the Technology Enablement Process (TEP) that the Company uses to determine if a technology provides customer benefits and is worth pursuing.[751]

Mr. McPhail explained that the Grid Automation portfolio is comprised of six core initiatives: 1) Distribution Circuit Modernization, 2) Substation Modernization, 3) Distribution Asset Management (DistAM), 4) Planning Systems Modernization, 5) Operational Systems Modernization, and 6) Weather Stations.[752] The Company projects total investments in Grid Automation of $25,691,000 in the bridge period and

[747] 3 Tr 1655. Grid Automation was previously referred to as Grid Modernization. 3 Tr 1658.
[748] 3 Tr 1660-1661.
[749] 3 Tr 1661.
[750] 3 Tr 1657-1658, 1660-1661.
[751] 3 Tr 1657-1659.
[752] 3 Tr 1660.

$17,837,000 in the test year.[753] Staff and intervenors take issue with capital spending within the Distribution Circuit Modernization and DistAM categories.

i. Distribution Circuit Modernization

Mr. McPhail testified that the Distribution Circuit Modernization initiative involves the integration and deployment of proven technologies commonly used by other utilities that result in improved reliability and increased resiliency on the LVD and HVD systems.[754] As presented in Figure 3 of Mr. McPhail's testimony, Distribution Circuit Modernization includes expenditures for two deployment projects (Line Sensors and Voltage Regulator Controllers) and six TEP projects (NOVA Triple-Single Recloser Communications, Line Recloser Modernization, Peer-to-Peer Automation, Supplemental Line Sensors, Metro Modernization, and Remote-Capable Switches).[755] Disputed issues involving Voltage Regulator Controllers and Metro Modernization are addressed below.

Voltage Regulator Controllers

Consumers forecasted $10,526,000 of capital expenditures in the bridge period and $5,120,000 in the test year for the Voltage Regulator Controllers project.[756] Mr. McPhail testified that voltage regulators adjust voltage on the electric distribution system based on changing load conditions to ensure customers receive energy delivered within tariff-specified limits.[757] He further explained that voltage regulators are remotely connected through the Advanced Distribution Management System (ADMS) via a communications-enabled controller to provide dynamic remote-control and monitoring

[753] 3 Tr 1663; Exhibit A-113.
[754] 3 Tr 1665.
[755] 3 Tr 1666.
[756] 3 Tr 1678.
[757] 3 Tr 1674.

capabilities.[758] Mr. McPhail stated that the Company plans to upgrade all controllers on voltage regulators installed on the electric distribution system.[759] The Company plans to upgrade 220 regulator locations in 2025 and complete the final year of deployment with 217 regulator locations in 2026; thereafter, the communicating regulator controller will be the standard installation as part of the Company's reliability programs.[760] Mr. McPhail provided a list of projects for the bridge period in Exhibit A-142, and for the test year in Exhibit A-143.[761]

Mr. McPhail sponsored Exhibit A-146, which is the Company's BCA on voltage regulator controllers.[762] He testified that voltage regulators benefit customers by improving power quality and efficient energy delivery.[763] He also stated that this project enables the CVR program, which achieves reduction of energy consumption and peak demand on the electric distribution system, as discussed in more detail by Company witness Partlan and in the Company's 2021 IRP in Case No. U-21090.[764] Mr. McPhail testified that the two-way communication capability avoids costs by enabling preventative maintenance and proactive replacement of units approaching end-of-life.[765] He added that proactively replacing equipment prior to failure can prevent customer outages and improve reliability, while preventative maintenance results in the life extension of voltage regulators, further reducing costs.[766] He stated that remote

[758] 3 Tr 1674-1675.
[759] 3 Tr 1677.
[760] 3 Tr 1677.
[761] 3 Tr 1678.
[762] 3 Tr 1675.
[763] 3 Tr 1675.
[764] 3 Tr 1676.
[765] 3 Tr 1676.
[766] 3 Tr 1676.

monitoring eliminates the need to deploy field crews to perform manual inspections.[767] Mr. McPhail further testified that by incorporating the ability to remotely monitor and control the voltage regulators with the installation of the modem, the Company saves on cellular costs due to the number of modems, on average, being reduced per location.[768] He also asserted that this program has resulted in avoided costs due to the replacement of older vintage materials with newer, more efficient materials.[769] Finally, Mr. McPhail testified that this investment benefits the Company's electric line workers through reduced exposure to electrical and traffic hazards.[770]

Mr. McPhail further testified that the unit cost for a regulator location is estimated based on material and labor costs associated with the number of phases, and existing health of the location.[771] He presented the Company's historical spending for this investment category and stated that the five-year average spending (2020-2024) is $4.76 million.[772] Mr. McPhail testified that variance in spending between years can be attributed to variance in the number of planned locations for each year as well as instances where material is purchased the year before the planned deployment to ensure the most efficient installation and use of available labor resources during the first few months of the following year.[773] He stated that as a result of a competitive bidding process with respect to construction labor, the Company identified a potential cost savings of about $1.5 million and that potential savings of $3,000 per unit for each

[767] 3 Tr 1676.
[768] 3 Tr 1676.
[769] 3 Tr 1676-1677.
[770] 3 Tr 1677.
[771] 3 Tr 1678.
[772] 3 Tr 1679.
[773] 3 Tr 1679.

location has already been incorporated into the funding requested.[774] Mr. McPhail added that average unit cost does not accurately reflect the expected spend per project due to shift in timing of material purchases, which could result in paying for two years of material in one calendar year and a relatively minimal amount of material the following year.[775] He added that material accounts for about 50% of the costs, and therefore dividing the annual cost by the annual units completed is not an effective method of understanding the unit cost.[776]

Mr. Coppola testified that in discovery, Consumers reported that it plans to install 294 units during the bridge period and 143 units in the test year.[777] Using the Company's forecasted bridge-period expenditures, Mr. Coppola stated that the average unit cost for 294 units is $35,803, which he testified is considerably higher than the $22,442 unit cost incurred by the Company in 2024 and the three-year average of $19,357.[778] For the projected test year, Mr. Coppola stated that the average unit cost for 143 units is $35,804, the same as the bridge period.[779] He stated that Mr. McPhail did not provide an explanation for the large increase in unit cost for the bridge period or the test year.[780]

Mr. Coppola calculated his proposed unit cost by adjusting the 2024 actual unit cost for inflation.[781] For the bridge period, this resulted in an average unit cost of $23,093, which multiplied by the number of units resulted in projected expenditures of

---

[774] 3 Tr 1679-1680.
[775] 3 Tr 1680.
[776] 3 Tr 1680.
[777] 3 Tr 2474-2475.
[778] 3 Tr 2475.
[779] 3 Tr 2475.
[780] 3 Tr 2475.
[781] 3 Tr 2475.

$6,789,000.[782] For the test year, the inflation-adjusted average unit cost of $23,647 multiplied by the number of units resulted in forecasted expenditures of $2,382,000.[783] Subtracting these amounts from the Company's forecasted amounts, Mr. Coppola recommended disallowances of $3,737,000 in the bridge period and $1,738,000 in the test year.[784]

ABATE witness Fitzhenry expressed concerns with the Company's BCA. He testified that the model fails to include several key costs borne by ratepayers, such as taxes, ROE, interest, and the possibility of stranded costs.[785] He testified that as a result, the Company's BCA presents a misleading picture of the project's cost-effectiveness, and a more accurate assessment that includes these costs would likely demonstrate the project is less cost-effective than the Company claims.[786] He stated that the Company's current BCA modeling approach is inappropriate for making investment decisions that directly impact customer rates.[787]

Mr. Fitzhenry further testified that the Company's input assumptions are unreasonable.[788] He stated that a majority of the monetized benefits, $12,880,000, are calculated based on the assumption that current line regulators installed prior to 2000 will all fail over the next 10 years, without an analysis to support this assumption.[789] He stated that excluding the forecasted benefit of future line regulator failures would reduce the NPV of benefits to $10,726,493, which is $4,402,645 less than the cash value of the

---

[782] 3 Tr 2475.
[783] 3 Tr 2475.
[784] 3 Tr 2475.
[785] 6 Tr 3731.
[786] 6 Tr 3731-3732.
[787] 6 Tr 3732.
[788] 6 Tr 3732.
[789] 6 Tr 3732.

project.[790] He added that in the alternative, if only 273 of the line regulators installed prior to 2000 fail, then the project's net benefits would be negative, and the project would no longer be forecasted to be cost-effective.[791]

Mr. Fitzhenry recommended that the Company reduce its proposed pace for the line regulator controller project to 25% of the proposed installation rate.[792] He stated that this would allow the Company to utilize actual historical data to validate and improve the input assumptions used in the BCA model, which the Company could provide in its next rate case.[793] Mr. Fitzhenry also recommended a corresponding reduction to the capital expense for this project, reducing expenditures by $7,894,500 in the bridge period and $3,840,000 in the test year.[794]

In rebuttal, Mr. McPhail disputed Mr. Coppola's unit-cost approach, recalling his direct testimony that such an approach is not appropriate because of instances where materials to be used for a subsequent deployment year were purchased in the year prior to deployment, or delayed into another year, thus giving an inaccurate view of unit costs when just comparing annual costs to the number of units.[795] Referencing Figure 7 in his direct testimony, Mr. McPhail stated that historical spending in 2023 and 2024 was relatively lower compared to 2020 through 2022 because the Company had leftover controls from the previous years, mainly 2022, as a result of the pull-ahead purchase of materials that helped offset costs in subsequent years.[796] He stated that those

---

[790] 6 Tr 3732.
[791] 6 Tr 3732.
[792] 6 Tr 3732.
[793] 6 Tr 3732.
[794] 6 Tr 3733.
[795] 3 Tr 1738.
[796] 3 Tr 1738; see Figure 7 at 3 Tr 1679.

additional controls have since been deployed, and the Company needs to purchase necessary materials in the bridge period and test year to complete the program.[797]

Mr. McPhail testified that he agreed "in part" with Mr. Fitzhenry's assessment of the Company's BCA, acknowledging that Mr. Fitzhenry correctly noted there are other costs beyond the initial purchase and installation price of voltage regulator controllers, such as taxes and ROE.[798] He stated that no standard has been established on what should be included in the BCA when evaluating electric distribution investments and that, in this case, the Company offered a BCA estimate of the value of this program.[799] He added that investment decisions on the electric grid are not solely based on a cost-effectiveness test, and he recalled his earlier testimony about other benefits customers see from this program, including improved power quality, a reduction of customer minute interruption (CMI) of 56,625 minutes as shown in Exhibit A-146, and reduced electrical and traffic exposure for line workers through the use of remote monitoring.[800] He opined that a holistic evaluation of all the benefits should be considered.[801]

Regarding the Company's assumptions in the BCA regarding the average life of a controller, Mr. McPhail testified that since the start of this project, the Company collected field data to better understand how these devices perform.[802] He stated that data from over 3,000 regulators showed that only five were manufactured in 1988 or earlier, demonstrating that the typical operation lifespan of these regulators does not

---

[797] 3 Tr 1738.
[798] 3 Tr 1739.
[799] 3 Tr 1739.
[800] 3 Tr 1740.
[801] 3 Tr 1740.
[802] 3 Tr 1740.

exceed 37 years.[803] In addition, about 60% of the regulators that failed during the project were manufactured before 2000, reinforcing the Company's confidence that the majority of field regulators, if not addressed by this project, would fail between 2027 and 2037.[804] Mr. McPhail stated that the BCA reflects that the average life of a control is 20 to 25 years, and it reasonably assumes (supported by the Company's empirical field data) that failures are more likely in the 10 years following that period.[805] He added that failures lead to poor power quality, negatively affecting customers and risking non-compliance with MPSC R 460.3702.[806]

Mr. McPhail further asserted that it is unclear how Mr. Fitzhenry arrived at his recommendation to slow the program to 25% of its current deployment rate.[807] He stated that slowing the installation rate will jeopardize the competitive contract described in his direct testimony and will erode the economies of scale that customers are benefiting from through a lower construction cost.[808] Mr. McPhail added that this program has been underway since 2020 and has received support in all prior rate cases, and the Company expects to complete the program in 2026.[809] He stated that the Company has already made investments in 2025 by purchasing materials for work in 2025 and the bridge period.[810]

In its initial brief, Consumers repeats Mr. McPhail's arguments in opposition to Mr. Coppola's unit-cost analysis. The Company asserts that material purchases do not

---

[803] 3 Tr 1740.
[804] 3 Tr 1740.
[805] 3 Tr 1740.
[806] 3 Tr 1740.
[807] 3 Tr 1741.
[808] 3 Tr 1741.
[809] 3 Tr 1741.
[810] 3 Tr 1741.

always match the year of deployment, resulting in a wide variance in historical unit costs, and it states that the Company needs to purchase materials in the bridge period and test year to complete the program.[811] Consumers also notes that unit costs have been as high as $39,252 in 2021, higher than the Company's $35,803 unit cost for the bridge period and test year.[812]

Consumers further argues that the Commission should reject Mr. Fitzhenry's proposed "dramatic reduction" to the installation rate of voltage regulator controllers and related capital expenditures.[813] The Company argues that Mr. Fitzhenry's proposal to slow the implementation rate to 25% of the current proposed rate is arbitrary and risks the benefits of the recent construction labor contract.[814]

In reply briefing, ABATE continues to promote a 25% reduction to the Voltage Regulator Controllers project, arguing that whatever purported benefits may be achieved by this program, they do not supplant the Company's burden to demonstrate its projected costs are reasonable or prudent.[815]

This PFD recommends that the Attorney General's proposed disallowance should be rejected. The Company has demonstrated that Mr. Coppola's average unit-cost approach is not appropriate because materials for this project are not purchased consistently on an annual basis. As Mr. McPhail explained, historical spending was lower in 2023 and 2024 because the Company had leftover materials from previous years; however, additional materials will need to be purchased for the bridge period and

---

[811] Consumers brief, 72-73.
[812] Consumers brief, 73.
[813] Consumers brief, 73.
[814] Consumers brief, 74.
[815] ABATE reply, 6-7.

test year, significantly increasing the unit cost above the 2024 level upon which Mr. Coppola's calculation relies.

Regarding ABATE's concerns, this PFD agrees that the BCA is flawed because it does not accurately portray the full costs of this project. However, this PFD disagrees with ABATE's proposed reduction to the installation rate of voltage regulator controllers and the related disallowance. Consumers has presented adequate evidence showing that the benefits of this program extend beyond the economic benefits addressed in a BCA.[816] In addition, the Company has installed more than 1,000 controllers since 2020, and the expenditures proposed in this case would enable the Company to complete its mass deployment with the installation of 437 units. This PFD agrees with the Company that Mr. Fitzhenry's proposal to slow the implementation rate to 25% of the current proposed rate is arbitrary and could prove counterproductive by jeopardizing the financial benefits of a competitive labor contract.

Metro Modernization

Consumers forecasted $305,000 of capital expenditures in the bridge period and $650,000 in the test year for the Metro Modernization investment category.[817] Mr. McPhail explained that the Company's Metro system provides necessary power to many downtown urban areas through a network of underground vaults.[818] He testified that the objective of this project is to provide technology options for upgrading to an

[816] See 3 Tr 1675-1677, 1740. See March 1, 2024 order in Case No. U-21389, p. 41 ("the Commission agrees with the company that BCA results are not the sole determinant of whether costs are reasonable and prudent").
[817] 3 Tr 1694.
[818] 3 Tr 1692.

advanced Metro vault standard.[819] He stated that the project will evaluate several areas: use of specialized sensors designed to detect water or gas hazards within the Metro system, assessment of switching equipment enhancements to enhance reliability and efficiency, development and integration of a communications package to facilitate seamless data exchange, and investigation of remote-control capabilities to streamline Metro operations.[820]

Mr. McPhail testified that the Metro Modernization project will enable safer and more effective operations; support situational awareness by introducing monitoring and control capabilities into metro vaults, reducing operational costs; enable proactive maintenance and inspection, leading to further reduction in costs; and support reliability by speeding up operations and outage restoration.[821] He stated that projected avoided CMI is shown in Exhibit A-151, adding that while the CMI component may seem small, the Metro system hosts a disproportionately larger percentage of commercial and priority customers such that reducing otherwise exceedingly long outages on the Metro system significantly impacts the customer experience.[822] Mr. McPhail also stated that by upgrading all vaults, there will be a meaningful reduction in work hours totaling 185 hours of exposure to dangerous confined spaces to electric line workers, and he asserted that the improved safety benefit for line workers alone necessitates this investment.[823]

---

[819] 3 Tr 1692.
[820] 3 Tr 1692.
[821] 3 Tr 1693.
[822] 3 Tr 1693.
[823] 3 Tr 1693; see Exhibit A-151.

Mr. McPhail further testified that the project will target one to two vaults to upgrade initially, and he described the Company's process for selecting locations that will maximize customer benefit.[824] He added that the requested investment in the bridge period and test year is not for a full system-wide deployment, but only the initial implementation of this technology.[825]

Mr. Coppola objected to the Company's proposed investments, recommending a full disallowance of bridge-period and test-year expenditures.[826] He testified there is no evidence the technology involved has worked effectively at other utilities and provided proven benefits, describing it as more experimental than tried and tested.[827] He added that the Company stated in discovery that it had not performed a BCA to demonstrate there is some economic value to this new technology.[828]

Although Mr. Fitzhenry did not specifically recommend a disallowance related to this project, he suggested that the project appears to be for research, and he criticized the lack of an estimate of system-wide deployment costs and a benefit-cost analysis.[829]

Mr. McPhail responded in rebuttal by reviewing the reliability and safety benefits of the program as presented in his initial testimony.[830] He stated that while safety incidents in underground Metro electrical systems are rare, they can be extremely

---

[824] 3 Tr 1693.
[825] 3 Tr 1694.
[826] 3 Tr 2476. In addition to Metro Modernization, Mr. Coppola recommended a full disallowance of forecasted capital expenditures for the Peer-to-Peer Automation project ($895,000 in the bridge period and $270,000 in the test year) based on his argument that the technology involved is experimental and unproven. *Id*. In rebuttal, Mr. McPhail testified that although the Company does not agree with Mr. Coppola's objections to the Peer-to-Peer project, it agreed to withdraw the projected expenditures from this case. 3 Tr 1745; Consumers brief, 75.
[827] 3 Tr 2476.
[828] 3 Tr 2476.
[829] 6 Tr 3736 n 44.
[830] 3 Tr 1746.

dangerous if they do happen, citing a news article from Boston involving a manhole explosion.[831] He stated that the sensing and switching technology the Company plans to deploy is not new or experimental in the industry but is only new to the Company.[832] Mr. McPhail added that the direction of this project is to engineer how these proven technologies will be used in the Company's system to benefit customers.[833]

In her initial brief, the Attorney General argues that, unlike reclosers, regulators, and sensors, which have been in use for years and are proven technology, the new technology that the Company wants to evaluate in this project is unproven and the claims of reliability and safety exposure are unsupported.[834] She further asserts that the Company indicated in discovery that employees spend around 2,000 hours in underground vaults, meaning that a 185-hour reduction represents a relatively minor reduction in safety exposure.[835]

This PFD agrees with the Attorney General that Consumers has failed to adequately support its costs for this project. If the Company seeks recovery of related expenditures in a future rate case, it should provide a complete picture of the total costs involved for full system-wide deployment as well as a BCA. The Commission should therefore disallow $305,000 in the bridge period and $650,000 in the test year.

ii. Distribution Asset Management

Mr. McPhail testified that DistAM is the application of asset management principles and processes to electric distribution assets to maximize the usefulness and

---

[831] 3 Tr 1746.
[832] 3 Tr 1746.
[833] 3 Tr 1746.
[834] Attorney General brief, 77.
[835] Attorney General brief, 77.

realization of value over their lifecycle, resulting in improved reliability through reduced equipment failure.[836] He stated that DistAM will develop lifecycle management capabilities by collecting key asset data to drive a risk-informed, value-based decision-making methodology to manage and optimize asset investments.[837] The components within DistAM will collect distribution asset data into a single centralized database that provides enhanced integration into asset health performance analysis, and investment strategy platforms.[838] Mr. McPhail explained that DistAM is distinct from ADMS because it focuses on the lifecycle asset management rather than real-time operational management of assets.[839]

Mr. McPhail further explained that the Company's DistAM strategy has three key workstreams: Asset Repository (AR); Asset Performance Management (APM); and Asset Investment Planning (AIP), which is now complete.[840] He stated that AR provides a single, centralized database to store essential distribution asset data, and he discussed the objectives, capabilities, and benefits of AR.[841] Mr. McPhail described APM as encompassing the capabilities of data capture, integration, visualization, and analytics tied together to improve the reliability and availability of physical assets, and he further discussed the objectives, capabilities, and benefits of the APM tool.[842]

---

[836] 3 Tr 1701.
[837] 3 Tr 1701.
[838] 3 Tr 1701-1702.
[839] 3 Tr 1702.
[840] 3 Tr 1702.
[841] 3 Tr 1704-1708.
[842] 3 Tr 1708-1710.

Mr. McPhail sponsored Exhibit 152, which is a BCA for DistAM, including all necessary components of AR, APM, and AIP.[843] He testified that the analysis performed in the BCA is on the full implementation of DistAM across all in-scope electric assets.[844] He noted that the requested investment in the bridge period and test year does not include the full system costs, and he stated that the Company will request, in future rate cases, the needed funding to complete the full implementation of this technology.[845]

As shown in Figure 9 of Mr. McPhail's testimony, Consumers forecasted total DistAM capital expenditures of $1.740 million in the bridge period ($0.970 million for AR and $0.770 million for APM) and $4.050 million in the test year ($1.410 million for AR and $2.640 million for APM).[846]

Mr. McPhail testified that since the launch of DistAM, the Company has invested $7.9 million as of March 31, 2025, including $5.8 million for AIP (launched in 2024), $2.1 million for AR, and no spending on APM.[847] He stated that the Commission originally approved DistAM in Case No. U-20697 and re-approved the project in Case No. U-20963.[848] He stated that the concept approval at that time projected an estimated $12 million for the project, and he added that in Case No. U-21585 the Commission held that approval of increased costs would require updated data.[849] Mr. McPhail testified that including the prior investments through the test year, the Company's current total

---

[843] 3 Tr 1706, 1709.
[844] 3 Tr 1706, 1709.
[845] 3 Tr 1706, 1709.
[846] 3 Tr 1703.
[847] 3 Tr 1703.
[848] 3 Tr 1703.
[849] 3 Tr 1703.

projected spend for the DistAM program is $13.6 million.[850] He provided the following explanation for why costs have increased from the original projected amount:

> Through the purchase and implementation of the AIP in 2024 and continued build out of the AR, more refined costs are now known to build a DistAM solution. As the project advanced, the Company discovered the need for the expansion of additional IT applications that were not initially scoped. Reviews were conducted on the quality of the Company's data and determined it would not meet the requirements of a vendor provided solution for an APM. The initial approach of the Company was to purchase the APM solution and implement similar to the AIP. However, as the Company's asset maturity continues to improve, it was deemed a better value to build an internal APM solution that will meet most of the requirements. It is estimated a vendor provided solution for an APM would cost $7.5 million to implement in year one with an estimated $1 million annual software as a solution agreement. Instead, the Company will build its own APM, estimated at $4.2 million with no software agreement cost.[851]

Mr. Coppola objected to further investments in the DistAM program. He testified that the Company reported in discovery that the original estimated cost of the AR system was approximately $2.5 million (including O&M costs), but it now forecasts the cost will be $8.8 million.[852] The Company further reported that the project proved to be more complex and costly as it progressed and that the software-as-a-service model tool was higher than originally forecasted.[853] Mr. Coppola opined, "This is a classic case of not doing enough upfront research and analysis, making a decision to proceed with a project based on sketchy information, and finding out later that the cost mushroomed to five times more than originally estimated."[854] Mr. Coppola also opined that the APM

---

[850] 3 Tr 1703.
[851] 3 Tr 1704.
[852] 3 Tr 2477.
[853] 3 Tr 2477.
[854] 3 Tr 2477.

system is still in the planning phase of development, and it is premature to include its capital spending in this rate case.[855]

Regarding the BCA, Mr. Coppola noted that it incorporates all the systems that the Company wants to implement, including—in addition to AR, APM, and AIP—the Device Management system.[856] He stated that this system is newly added in this rate case at a cost of $2.5 million, without explanation or justification.[857] Mr. Coppola further testified that the BCA is based on the original total cost of all systems of approximately $16 million instead of the current forecast of nearly $21 million, and is therefore "stale."[858] He stated that with the new higher cost, the net present value is no longer favorable and is now about to break even, assuming all of the soft savings in the BCA are achievable.[859] Mr. Coppola took further issue with the Company including cost savings attributed to "Societal Improved Power Quality" and reduced "Reliability Degradation Risk," describing them as vague concepts that are not likely to provide tangible and realistic cost savings.[860] Mr. Coppola opined that the Commission should not rely on any representations from the Company that the proposed systems are economically justified.[861]

Mr. Coppola concluded that customers should not pay for projects that are incurring significant cost overruns and are not economically justified.[862] He

---

[855] 3 Tr 2478-2479.
[856] 3 Tr 2478.
[857] 3 Tr 2478.
[858] 3 Tr 2478.
[859] 3 Tr 2478.
[860] 3 Tr 2478.
[861] 3 Tr 2478.
[862] 3 Tr 2478.

recommended that the Commission disallow all proposed expenditures in the bridge period and test year.[863]

Staff witness Shi testified that although the DistAM program has been in place for more than three years, the Company has yet to make expenditures on the APM component.[864] She stated that in Case No. U-21585, Consumers had projected APM expenditures of $1.226 million in the bridge period and $6.248 million in the test year.[865] Ms. Shi noted the Commission's disallowance of $5.558 million related to DistAM in that previous case, and she stated even if that entire amount was attributable solely to APM, approximately $0.69 million would have remained available for the Company to spend.[866] Ms. Shi testified that the Company has not provided adequate details explaining why previously authorized funds were not spent on APM and how projected funds will be used in the bridge period and test year, preventing Staff from validating whether additional expenditures are reasonable and prudent.[867] As a result, Ms. Shi recommended disallowing the full amount of proposed APM expenditures, equaling $770,000 in the bridge period and $2,640,000 in the test year.[868]

In rebuttal, Mr. McPhail testified that in response to the Commission's finding in Case No. U-21585 that Consumers failed to provide adequate data to support recovery of increased costs of the DistAM program, the Company has provided updated data and additional justification in this case, along with a BCA showing future year expenses.[869]

---

[863] 3 Tr 2479.
[864] 6 Tr 4489-4490.
[865] 6 Tr 4490.
[866] 6 Tr 4490.
[867] 6 Tr 4490.
[868] 6 Tr 4491.
[869] 3 Tr 1742-1743, 1744-1745.

He testified that the total projected spend through the test year is $13.6 million, which is only $1.6 million more than the previously approved amount.[870]

Mr. McPhail disagreed with Mr. Coppola's proposed disallowances, testifying that the requested amounts are necessary to continue the development and deployment of this initiative and that each of the three primary components all build on each other to improve capital efficiency.[871] He stated that 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.[872] He noted his earlier testimony that the Company avoided $3.3 million in capital and $1 million in O&M expense by building an internal APM solution, adding that these annual O&M savings were not included in the BCA.[873] Mr. McPhail further testified that it is incorrect to exclude APM funding because it is in the planning phase, stating that the APM is scalable and the entire APM does not need to be complete to begin extracting value out of it.[874] He added that funding is being requested through April 2027, which provides a year after the planning phase to add in assets and leverage their health scores as each asset is brought in.[875]

In response to Ms. Shi, Mr. McPhail testified that the APM is highly dependent upon the AR because the source data needed to calculate the asset health score will come from the AR.[876] He stated that funds have not been spent on the APM because the Company determined it was more efficient to shift focus to add more assets into the

---

[870] 3 Tr 1743.
[871] 3 Tr 1743.
[872] 3 Tr 1743.
[873] 3 Tr 1743.
[874] 3 Tr 1743.
[875] 3 Tr 1743-1744.
[876] 3 Tr 1744.

AR versus further development of the APM.[877] He asserted that, given the interdependencies between the three workstreams, it is more appropriate to consider DistAM as a whole, and he stated that the Company has made progress on the overall DistAM program by completing the AIP and being on track to have seven electric assets in the AR by the end of 2025.[878]

Mr. McPhail testified that completion of a holistic DistAM initiative is supported by the Liberty Audit.[879] He also stated that in Case No. U-20147, the Commission required the Company to provide a data-based review of the general health and condition of its distribution system assets, which the DistAM program aims to deliver, and he added that failure to approve this investment risks the level of detail the Company will be able to provide in compliance with that order.[880]

In initial briefing, the Attorney General continues Mr. Coppola's arguments that the Company's failure to perform adequate upfront research has resulted in a substantial increase in cost for the AR system and that the BCA fails to establish that the overall DistAM program is economically justified.[881] Regarding the APM, the Attorney General states that the Company confirmed in a discovery response that the system is still in the planning phase, supporting her argument that it is too premature for this rate case.[882]

In its brief, Staff agrees with the Attorney General's position that more research should have been performed before proceeding with the DistAM initiative and that it is

---

[877] 3 Tr 1744.
[878] 3 Tr 1744.
[879] 3 Tr 1711, 1745.
[880] 3 Tr 1745.
[881] Attorney General brief, 78-80.
[882] Attorney General brief, 80.

premature to include APM expenditures in rate base.[883] Staff further argues that the Company's rationale—that its own internal reprioritization caused the lack of APM investment—underscores significant deficiencies in overall program planning and execution and cannot serve as a basis for approving additional ratepayer-funded APM expenditures.[884] It continues by arguing that if Consumers had approached DistAM holistically from the outset, it should have developed a more disciplined schedule, budget, and sequencing plan reflecting the interdependencies among AR, APM, and AIP.[885]

This PFD shares the concerns expressed by Staff and the Attorney General regarding the spending and overall management of this project. In Case No. U-21389, the Commission expressed support for continuation of the DistAM project but noted that the project was originally approved with projected total costs of $12 million and that the original projection had been reached.[886] The Commission therefore required "updated data, including total costs, for any future cost recovery requests associated with the DistAM project."[887] In Case No. U-21585, the Commission referenced its mandate from the previous case and found that Consumers had failed to provide adequate data supporting recovery of the increased costs associated with DistAM, disallowing $5.558 million in expenditures for the program.[888]

Here, Consumers supports its DistAM spending with a flawed BCA that is based on outdated costs and includes anticipated cost savings that are vague and unrealistic.

---

[883] Staff brief, 22-23.
[884] Staff brief, 23.
[885] Staff brief, 23.
[886] March 1, 2024 order in Case No. U-21389, p. 41.
[887] March 1, 2024 order in Case No. U-21389, p. 41.
[888] March 21, 2025 order in Case No. U-21585, p. 110.

The BCA's deficiencies are especially problematic given the Company's history of overspending on this project and the Commission's requirement that additional costs be supported with updated data. In addition, the Company's explanations for its cost overruns and lack of APM investment essentially boil down to inadequate initial research along with poor planning and execution. In the end, Consumers has not shown that its projected expenditures are reasonable and will provide adequate value to ratepayers. As such, the Commission should disallow $1.740 million in the bridge period and $4.050 million in the test year.

2. Streetlighting Capital Expenditures

Mr. Schmoekel testified in support of the Streetlighting Program requests in this case.[889] His testimony described the Company's streetlighting assets, the Company's strategic plan for management of those assets, the reasonableness and prudence of the capital expenditures for the conversion of overhead-fed cobrahead streetlights, the reasonableness and prudence of the capital expenditures for the conversion of high intensity discharge ("HID") overhead-fed cobrahead streetlights that are located in the vicinity of failed overhead-fed cobrahead fixtures, the reasonableness and prudence of the capital expenditures for the installation of new customer-requested streetlighting assets , and the Company's streetlight outage restoration performance.[890]

Mr. Schmoekel explained that the Company owns and maintains approximately 173,000 streetlights, most of which are cobrahead fixtures. In addition to the 119,000 cobrahead fixtures, the Company has approximately 11,000 center suspension

[889] 3 Tr 2070-2118.
[890] 3 Tr 2072.

streetlights and approximately 43,000 post-top fixtures.[891] The streetlights the Company owns primarily fall in one of two buckets: HID and light emitting diode ("LED"). HID luminaires include mercury vapor ("MV"), high pressure sodium ("HPS"), and metal halide ("MH"). The MV, MH, and LED streetlights typically have a similar color temperature (white light) whereas the HPS streetlights typically have an amber color.[892]

Mr. Schmoekel further discussed the Company's Streetlight Outage and Restoration ("SOAR") application, its streetlight patrol and fix initiative, the Company's completed initiative for advanced lighting controls, and the development of a modified conversion plan for its HID cobrahead and post top fixtures—all to support improved outage restoration performance.[893]

Mr. Schmoekel also noted that Consumers met with Michigan Municipal Association for Utility Issues ("MI-MAUI") seven times in 2024 to discuss streetlighting reliability reporting, and operational progress toward identifying opportunities for improvement and enhancement in customer experiences. The Company also expressed its intent to continue to collaborate with MI-MAUI and other parties to address streetlighting concerns.[894]

The Company projected $26.432 million of streetlighting capital expenditures for the 16-month bridge period, and $16.545 million of streetlighting capital expenditures for the test year.[895] These totals include 1) $4.869 million (bridge period) and $3.727 million (test year) for streetlighting new business; 2) $1.334 million (bridge period) and $1.018

---

[891] 3 Tr 2073.
[892] 3 Tr 2074.
[893] 3 Tr 2075.
[894] 3 Tr 2075.
[895] 3 Tr 2113.

million (test year) for planned LED conversions in the vicinity of an LED demand failure conversion; and 3) $20.229 million (bridge period) and $11.800 million (test year) for streetlight Demand Failures, as shown in Exhibit A-12, Schedule B-5.9.

Ms. Duell testified that Staff recommends that the Company be more descriptive and detailed when replying to discovery questions. According to Ms. Duell, Staff asked the Company where the remaining $1,056,000 in unspent funds for streetlighting had gone in 2024; however, the Company response did not give Staff any information on why the Company underspent in streetlighting for 2024 or where the remaining $1,056,000 had been allocated.[896]

Ms. Duell noted that in 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."[897] According to her, the Company did not comply; and in the future she recommended the Company keep track of its underspend in programs related to distribution expenditures. Ms. Duell explained that if the Company were to underspend in any program for which the Company was requesting expenditures in a rate case, the Company could then provide Staff detailed information on where those underspent amounts were shifted when such information was requested. If the Company cannot provide Staff with detailed information regarding where unspent funds were reallocated to, then Staff may recommend disallowances in future rate cases.

---

[896] 6 Tr 4396-97.
[897] 6 Tr 4397.

In response, Mr. Schmoekel specifically disagreed with the suggestion that Consumers 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 specifically identified.[898] Regarding Electric Distribution capital programs, Mr. Schmoekel explained that 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 because unused funds in one program and capital needs in other programs often occur at different times. As a result of this process, there are no more details the Company could have provided in response to Ms. Duell's question.[899]

Mr. Schmoekel asserted that Consumers complied with the Order in Case No. U-21585. The Company provided Staff with as much detail as possible regarding the application of excess funds for Streetlighting in all relevant discovery responses; however, the Company could not provide detail that did not exist.[900] Mr. Schmoekel recommended that the Commission reject Staff's claim that the Company failed to follow the Commission's Order in Case No. U-21585 because the Company demonstrated that unused streetlighting funds were allocated to distribution capital spending.[901]

In its brief, the Company argues that the Commission should approve the Company's Streetlighting Capital Expenditures.[902] The Company reiterates its testimony

---

[898] 3 Tr 2117.
[899] 3 Tr 2117.
[900] 3 Tr 2118.
[901] 3 Tr 2118.
[902] Company brief, p. 82.

and asserts that capital investments for streetlighting are well-supported and reasonable. The Company then asserts the Commission should approve the Company's capital spending proposal for the bridge year and the test year as filed.[903]

The Company notes that its overall total distribution capital investment in 2024, which exceeded the amounts approved by the Commission with actual distribution capital spending in 2024 of $920.4 million compared to the rate case forecasted amount of $807.9 million.[904] The unspent $1 million from streetlighting was utilized to help fund that shortfall; therefore, the Commission should reject Ms. Duell's claims as unwarranted.[905]

In its brief, Staff reiterates its recommendation, emphasizing that if the Company cannot provide Staff with detailed information regarding where unspent funds are being reallocated to then Staff may recommend disallowances in future rate cases.[906]

This PFD concurs with Staff in part, that the Company should be able to explain why it underspent in Streetlighting. However, this PFD agrees with that once funds become available due to underspending, it may be difficult if not impossible to precisely detail where those funds were ultimately reallocated. Therefore, this PFD recommends the Commission direct the Company to ensure it can adequately justify any underspend and trace those dollars when they are spent, to the degree that it can, to ensure the Company spend approved dollars reasonably and prudently.

---

[903] Company brief, pp. 82-83.
[904] Company brief, p. 84.
[905] Company brief, p. 84-85.
[906] Staff brief, p. 193-94.

3. Generation Capital Expenditures

a. Overview

Mr. Blumenstock presented generation capital expenditures, set forth in Exhibit A-12, Schedule B-5.2: $145.252 million for the historical year ending December 31, 2024; $275.408 million projected for the 16-month bridge period ending April 30, 2026; and $188.638 million for the projected test year ending April 30, 2027.[907] The exhibit is broken down by steam power generation, hydraulic power generation, pumped storage generation, and other production plant, with projects identified as routine or non-routine, and further detailed into contractor, labor, materials, business expenses, contingency, and other.[908] Mr. Blumenstock testified that Consumers did not include any contingency amounts in its projections.[909]

Mr. Blumenstock identified the major drivers of Consumers' capital investments as plant safety, regulatory compliance, and reliability.[910] Projects not strictly required for regulatory compliance and/or continued operations are generally subject to internal rate of return (IRR) and present value ratio (PVR) analysis to evaluate and prioritize those projects, with the Company using an overarching least cost/best fit (LCBF) analysis for necessary investments.[911] Customer benefit is measured by replacement power cost estimates and PSCR impacts, as well as random outage rate (ROR) and heat rate improvements that increase generation and/or lower cost generation.

---

[907] 6 Tr 3495-3552.
[908] 6 Tr 3495-3496
[909] 6 Tr 3502-3503.
[910] 6 Tr 3495, 3497, 3501.
[911] 6 Tr 3497-3498.

The Company also evaluates the costs of historical events impacting availability, and the actions needed to avoid them, and these are factored into the cost and availability projections through April 30, 2027.[912] Mr. Blumenstock stated that, to determine projected expenditure amounts, Generation System Planners assess equipment performance and compare the assessment for a generating unit with its generation asset strategy, completing a project initiation document (PID) identifying issues, alternatives for resolution, intended benefits or consequences avoided by the proposed course of action, recommended timing, and a cost estimate.[913] The cost estimate is based on past experience, contractor cost estimates, internal estimates, original equipment manufacturer (OEM) data, and studies.[914] Mr. Blumenstock testified that, after review, approved PIDs will be included in the long-term financial plan (LTFP) for three to five years in the future, with planning and engineering occurring in the meantime.[915]

Mr. Blumenstock outlined the differences between the $275.408 million in capital projects appearing on Exhibit A-12, Schedule B-5.2, with the 14-month bridge period capital projects in Case No. U-21585, Exhibit A-12, Schedule B-5.2.[916] He noted that $70.614 million is intended to fund BESS projects, $15.225 million will fund projects at the Ludington Pumped Storage (LPS or Ludington) facility, and $171.787 million is to be used at Consumers natural gas generating facilities, including Covert, Jackson,

[912] 6 Tr 3499.
[913] 6 Tr 3501.
[914] 6 Tr 3502.
[915] 6 Tr 3501.
[916] 6 Tr 3505-3512.

Zeeland, and Karn Units 3 and 4 for the bridge period.[917] The $188.638 million in projected capital expenditures for the test year on Exhibit A-12, Schedule B-5.2, allot $26.392 million to fund BESS projects; $137.913 million for natural gas generating facilities; and $13.282 million for regulatory, reliability, and infrastructure projects "to support the 50-year license extension at Ludington granted by FERC in 2019."[918]

Mr. Blumenstock also presented the Company's planned major outages of 28 days or longer in duration, listed in Exhibit A-41, and testified that the planned outages and their duration informed the periodic factors (PFs) in Exhibit A-42.[919] He explained the considerations in scheduling outages, noting that the Company's generation asset and investment strategies focus on a generating unit's ability to provide economic value to customers through production and through capacity value in MISO markets.[920] Outage schedules maximize availability when market pricing is projected to be high, but scheduled outages and forecasted capital expenditures could change in the future because the circumstances and available information between approval and outage can change over the long lead times.[921] The outage schedule can be influenced by contractor availability, parts availability, changes in regulations, design changes, outage scope changes, unit condition changes, and spot market prices, with disallowance of capital projects causing cancellation of work scope and outage plans, and impacting facility availability.[922]

---

[917] 6 Tr 3512.
[918] 6 Tr 3512.
[919] 6 Tr 3465-3468.
[920] 6 Tr 3467-3471.
[921] 6 Tr 3499-3500.
[922] 6 Tr 3465, 3500.

Staff recommends reducing generation capital expenditures by $12,908,000, which results in an $8,680,000 reduction to rate base.[923] These recommendations will be discussed, below.

b. Fossil Generation and Ludington Pumped Storage

i. Updated Cost Projections

Mr. Blumenstock presented the bridge period and test year investments for the Covert Generation Facility (Covert), the D.E. Karn Generating Plant (Karn) Units 3 and 4, Zeeland Generating Station (Zeeland), Jackson Generating Station (Jackson), and the Ludington Pumped Storage Plant (Ludington or LPS). Mr. Blumenstock stated that Consumers intends to invest $67.545 million during the 16-month bridge period and $61.443 million at the Covert Plant during the test year, with seven of the bridge period projects costing greater than $1 million.[924]

Consumers plans capital investments of $12.478 million in Karn Units 3 and 4 for the 16-month bridge period, and plans to invest $8.304 million in the projected test year, with four of the projects for the bridge period classified as greater than $1 million.[925] For Zeeland, Consumers has planned investments of $67.275 million in the 16-month bridge period, and capital expenditures of $40.023 million for the Zeeland plant (Zeeland) for the projected test year.[926] For Jackson, Consumers intends to invest $24.489 million in the 16-month bridge period, and projects capital spending of $28.143 million in the test year.[927] And for Ludington, Consumers intends to make capital

[923] Staff brief, 28.
[924] 6 Tr 3513-3517.
[925] 6 Tr 3527-3528..
[926] 6 Tr 3531-3536. Exhibit A-12, Schedule B-5.2, pp. 8, 9, 2.
[927] 6 Tr 3536-3542.

investments of $15.225 million in the bridge period, and $13.282 million in the projected test year.[928] This PFD recommends approval of the uncontested capital investments, and discusses the contested capital investments, below.

Staff recommended updated projections for capital projects over $1 million for the bridge period resulting in the recommended removal of $5.453 million in the bridge period.[929] Staff witness Laura Maio testified that, in response to discovery, the Company provided actual amounts spent through June 2025 and updated capital expenditure projections for generation capital projects over $1 million.[930] Staff's reduction represents its calculation of the difference between the amounts in Consumers' original filing and the current amounts provided in discovery.

In response, Mr. Blumenstock testified that, in addition to the projects greater than $1 million originally presented in Exhibit A-12, Schedule B-5.2, page 8, the Company identified three additional projects totaling $6,920,267: the Karn Unit 4 Transformer Fire Capital; the Covert Main Steam Tee Header Replacements; and the Covert Unit 3 Main Steam Tee Header Replacements. These projects were emergent work that was performed through June 2025 for a total actual capital expenditure of $3,238,054.[931] They were determined to be a higher priority than those in the initial case filing.[932] Mr. Blumenstock opined that it would be inappropriate to disallow the $5.453 million based on Consumers' "re-prioritization of that capital to critical emergent projects

[928] 6 Tr 3542-3549, referencing Exhibit A-12, Schedule B-5.2, pages 3, 8, and 9.
[929] 6 Tr 4466.
[930] 6 Tr 4466 citing Exhibits A-12, Schedule B-5.2, p. 8, and Exhibit S-8.0.
[931] 6 Tr 3607.
[932] 6 Tr 3607-3608.

totaling $4,078,267 for the 2025 calendar year and $6,920,267 for the entirety of the 16-month bridge period."[933]

Mr. Blumenstock explained that the Karn Unit 4 capital project resulted from a fire in the main unit transformer in February 2025, necessitating restoration for both function and the Unit's MISO capacity value; restoration was reasonable and prudent.[934] The Covert Main Steam Tee Header Replacement resulted from a spring 2025 major inspection outage at Covert Unit 2, with multiple components showing as not suitable for continued service; most are being replaced or had welded repairs performed, with two tees still "being replaced by a fabricated tee assembly following consultation with industry experts."[935]

In its brief, Staff recommends a $6,641,000 reduction for capital expenditure projections for generation capital projects over $1 million in the bridge period, which is a $6,235,000 reduction to rate base.[936] Staff also recommends an increase in the projected hydro generation expenditures by $1,780,000, which is a $1,748,000 increase to rate base.[937] Staff reiterates that, based on the actual spending amounts and updated projections for these projects provided by the Company in discovery, it recalculated the bridge spending for the generation capital projects over $1 million; for the projects in the initial filing, the Company agrees with the adjustment.[938] However, the Company also included several additional projects exceeding $1 million to those initially filed that it now

---

[933] 6 Tr 3608.
[934] 6 Tr 3608-3609.
[935] 6 Tr 3609.
[936] Staff brief, 28, referencing Ms. Maio's testimony at 6 Tr 4466.
[937] Staff brief, 35-36.
[938] Staff brief, 28-29, 35-36, citing Exhibit A-12, Schedule B5.2, p. 8; Exhibit S-8.0; Exhibit S-8.1; 6 Tr 3607.

asserts should be considered. Staff asserts that these new requests submitted via discovery and rebuttal are inappropriate because they have not provided interested parties with proper justification and notice to permit satisfactory review of the evidence and mount an appropriate challenge.[939] On top of all of this, Staff takes the position that other generation should be reduced by $592,000 for the test year based on updated projections.[940]

Consumers' brief contends that Ms. Maio's adjustment fails to reflect the $6.920 million of capital spending in the bridge period for the Karn Unit 4 Transformer Fire Capital, the Covert Main Steam Tee Header Replacements, and the Covert Unit 3 Main Steam Tee Header Replacements, with actual capital spending of $3.238 million through June 2025.[941] Consumers takes the position that, based on Staff's adjustment, this results in an increase of $1.467 million for the bridge period.[942]

Staff is correct in its assertions that it is generally inappropriate for the Company to attempt to introduce new projects in discovery or rebuttal.[943] The impropriety of attempting to expand the record in an advanced stage of the case has already been examined at length, and rejected, in relation to improper rebuttal testimony.[944]

Furthermore, even considering the additional projects introduced in Mr. Blumenstock's rebuttal testimony, there is insufficient evidence to approve the requested spending. There is no evidence to support Mr. Blumenstock's assertion that inspections of Covert Unit 1 and Covert Unit 3 will reveal the same issues that were

---

[939] Staff brief, 29-30.
[940] Staff brief, 37.
[941] Consumers brief, 89.
[942] Consumers brief, 89.
[943] Staff brief, 30, citing the July 2, 2024 order in Case No. U-21461, p. 22.
[944] November 7, 2025, Ruling on Motion to Strike in Case No. U-21870.

found at Covert Unit 2.[945] Such project spending is speculative and indeterminate. The repairs that he indicates have been completed at Covert Unit 2 involve issues that were addressed by being blended out, ground out, or welded; it is unclear why these are not ordinary repairs covered under the emergent repairs budget, as testified to by Mr. Guinn.[946] The other repairs involve parts that are "being replaced."[947] Without a more complete presentation of evidence regarding the cost of these individual, in progress replacements, Consumers has not carried its burden of proof to allow the newly requested capital spending. The same is true of the Karn Unit 4 transformer fire capital project expenditures now being claimed by the Company.

However, while the timing and lack of complete evidence precludes the Company's recovery of the newly claimed capital projects in this case, Staff's Exhibit S-8.1 setting forth the bridge period adjustments shows a reduction of $5,453,000. Ms. Maio testified that Staff is seeking a $5.453 million reduction for capital projects over $1 million in the bridge period.[948] This PFD recommends disallowance of the $5.453 million based on the agreed recalculation of the existing projects set forth in Exhibit S-8.1.

ii. Staff Adjustments

Ms. Maio presented Staff's recommended $7.455 million reduction for the test year for capital projects over $1 million based on the class cost estimate of specific projects.[949] She described Consumers' internal cost class estimate standards, and the expected accuracy of early stage projects versus those at closeout when all engineering

---

[945] 6 Tr 3609.
[946] 6 Tr 3609. 3 Tr 553, 626.
[947] 6 Tr 3609.
[948] 6 Tr 4466.
[949] 6 Tr 4466, 4469.

work was complete, including a table of the expected accuracy of projections expressed as a percentage range.[950] Ms. Maio explained that, for projects over $1 million where "the engineering component was not one hundred percent known," Staff used the lower end of the expected accuracy range for each class estimate level to estimate costs.[951] Staff made these adjustments after requesting updates to the projected amounts from the Company; no changes were provided. Staff's calculation of spending at the lower end of the accuracy range is for projects where the engineering component was still undetermined, forming the basis for the recommended reduction.[952]

Mr. Blumenstock responded that, of the 17 projects for which Ms. Maio recommended a downward adjustment, all but five are non-routine, with ten of the projects supported by Consumers' Association for the Advancement of Cost Engineering (AACE) Class 2 estimates, and with five having AACE Class 3 estimates.[953] He disagreed with the use of the low end of the accuracy range forming the basis for Staff's proposed disallowance, noting that the projected amounts do not include contingency.[954] Use of the lower end of the accuracy range for all large generation projects will prevent Consumers from recovering actual costs expended for completion of the projects for "at least the first year those projects are in service."[955] The asset will begin depreciating as soon as it is placed in service, but the Company will not be compensated for the use causing depreciation during that time. According to Mr. Blumenstock, Consumers will be compensated in the second year of use when the

---

[950] 6 Tr 4467-4468.
[951] 6 Tr 4468-4469, citing Exhibits S-8.0, S-8.3, and S-8.4.
[952] 6 Tr 4469.
[953] 6 Tr 3610.
[954] 6 Tr 3610-3611.
[955] 6 Tr 3611.

investment is put into rates, and will be compensated "throughout the remaining life of the asset, but it will never be reimbursed for the first year of uncompensated use at a later time."[956] In addition, due to Staff's artificially low estimate, the Company will never recover a return for investments in the first year of service that were reasonably and prudently incurred.[957]

Mr. Blumenstock opined that awarding only the low end of the accuracy range would cause Consumers to "de-prioritize several projects" to cover the disallowance by reduced investment, resulting in the inevitable "degradation of reliability and safety" without the projects being completed as planned.[958] He considered it "statistically improbable" that all of the larger test year projects would result in spending at the bottom end of the accuracy range, asserting that the actual costs would likely be those estimated by the Company; he contended that historical costs bear this out, with 2024 capital project spending exceeding the projected capital for those projects.[959] The ranges by class level have an 80% confidence interval, and, as a result, there is a very low probability that all of the projects will have an actual cost at the low end of the accuracy range. Mr. Blumenstock concluded that it is not reasonable to assume that all the estimates will be high, and that actual cost will be at the bottom of the accuracy range.[960]

Mr. Blumenstock also advanced the idea that the Company has already removed its initially calculated 5% contingency for the projects based on prior Commission

---

[956] 6 Tr 3611-3612.
[957] 6 Tr 3612.
[958] 6 Tr 3612.
[959] 6 Tr 3612-3613.
[960] 6 Tr 3614.

orders, so the universal use of the low end of the accuracy range is removing the 5% contingency amount a second time. He contended that "[a]t 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."[961]

More concretely, Mr. Blumenstock testified that, for projects not projected to close during the test year, namely the Covert spare GSU project and the Zeeland Phase II gas turbine advanced gas path replacement and axial fuel staging project, their revenue requirement is offset by AFUDC. As a result, Mr. Blumenstock contended that the $0.591 million proposed disallowance for Covert, and the $1.392 million proposed disallowance for Zeeland, should be rejected.[962] Consumers' brief reflects the balance of Mr. Blumenstock's testimony.[963]

Staff's brief recommends reducing steam generation class cost capital expense estimates by $6,536,000, and hydro generation class cost estimate capital expenditures by $918,000.[964] Out of 22 total projects over $1 million, this would reduce a total of 17 projects, 13 steam projects and 4 Ludington projects, to the lower bound of the accuracy range based on the most recent class cost estimate for projects where "the engineering component was not 100% known."[965] Staff noted that the Commission ruled in favor of this approach in Case No. U-21585, finding reasonable reductions to the lower bounds of the cost class estimate ranges for a limited number of projects where at

[961] 6 Tr 3613-3614.
[962] 6 Tr 3612, 3614.
[963] Consumers brief, 90-94.
[964] Staff brief, 30, 36.
[965] Staff brief, 30-31, 36.

least some proportion of the total projects was likely to be in the low end of the class estimate.[966]

Staff takes issue with the Company's response, noting that only 17, and not all, projects over $1 million in the test year have been adjusted, and these are due to the fact that, "the further into the future a projected amount is estimated for a project, the more uncertainty in the cost estimate."[967] The total capital expenditures of $74,547,493 for the 17 projects represent only 46% of the $162,245,908 total generation capital expenditure request, excluding battery storage expense. The remaining 54%, or $87,698,415, in total generation capital expenditures for the test year have not been adjusted by Staff.[968] Staff asserts that using "the lower end of the accuracy range of the estimate is a reasonable mechanism to quantify the uncertainty associated with each project cost estimate," noting that it has used, and the Commission has accepted, this method in Consumers' electric rate Case Nos. U-21389 and U-21585.[969] In addition, the Company can still request recovery of actual amounts expensed in future rate cases if warranted as projections are updated and spending occurs.[970]

Staff also disagrees with Consumers' position that the Covert spare GSU project and the Zeeland Phase II gas turbine project subject to AFUDC should be removed, and Staff disputes the propriety of reducing the disallowance by a 5% contingency.[971] Staff states that the reasoning for the recommended disallowance is due to uncertainty of projected costs in the test year, and that the reductions for the two specific projects are

---

[966] Staff brief, 31-32, citing the March 21, 2025 order in Case No. U-21585, pp. 128-129.
[967] Staff brief, 33.
[968] Staff brief, 33.
[969] Staff brief, 33-34.
[970] Staff brief, 34.
[971] Staff brief, 34-35.

appropriate, irrespective of whether the revenue requirement will be offset by AFUDC.[972] Similarly, Staff rejects the introduction of a contingency amount to projected capital expenditures, stating that it has not had time to verify every component of the project cost estimates, and that there is no assurance that project cost estimates were not inflated within their components and stages.[973]

In its reply brief, Staff counters Consumers' claims that it will never recover lost depreciation, even if the Company requests recovery of actual costs in the next electric rate case. Staff notes that the reverse is true for ratepayers who will never receive reimbursement if they prepay for a project where the actual costs are less than those approved based on projections.[974] Staff interprets Consumers to be arguing for reconsideration of the logic leading the Commission to approve Staff's disallowances in Case No. U-21585 for the reason that 2024 generation capital expenditure was higher than projected generation capital expenditure in that year. Staff responds that 2023 generation capital expense was lower than what had been projected.[975] To Staff, this illustrates the uncertainty of projections, and Staff maintains that using the lower end of the accuracy range is a reasonable mechanism for quantifying that uncertainty.[976]

Staff points out that the Company's Exhibit A-12, Schedule B-5.2 actual spending amounts shows several new projects with actual spend over $1 million that were not projected in 2024; several projects over $1 million in 2024 had increased actual spending over their initially projected amount due to project changes; and the sum of

---

[972] Staff brief, 34.
[973] Staff brief, 35-36.
[974] Staff reply, 2-3.
[975] Staff reply, 3.
[976] Staff reply, 3-4.

the projected amounts exceeding $1 million remains slightly higher than the actual spending for the same projects.[977] As a result, Staff contends that, contrary to Consumers' concerns, there is no guarantee that new project costs will increase dramatically in the future; escalation of costs is not a foregone conclusion.[978] Furthermore, Staff is only adjusting projected amounts where project cost estimates are not as clearly defined.[979] Staff therefore repeats it recommendation for a $7.455 million reduction for steam and hydro (pumped storage) generation capital expenditures based on class cost estimate.[980]

"As the Commission has repeatedly found, while allowing for contingency may be appropriate in project planning, the inclusion of these uncertain costs in customer rates is unjust and unreasonable."[981] For this reason, this PFD recommends against reintroducing a 5% contingency to offset Staff's proposed reduction. In relation to the two projects offset by AFUDC, this PFD finds persuasive Staff's position that any allowed spending is based on reasonableness, not solely rate base, and the reasons for disallowing spending for the other projects is applicable to these two.

As for the reasons for disallowing the projected test year spending based on class cost estimates as recommended by Staff, the recommended disallowances are by no means geared towards every project. They are geared towards projects where the engineering costs are still unknown, and the projects are still in relatively early stages of planning with uncertain costs. Consumers can seek recovery of future amounts in future

---

[977] Staff reply, 4.
[978] Staff reply, 4.
[979] Staff reply, 4.
[980] Staff reply, 4-5.
[981] December 9, 2021 order in Case No. U-20940, pp. 9-10, citing several other orders for the same proposition.

rate cases once projections are better documented, or costs are actually incurred, should the allowed amounts result in insufficient funding. Contrary to the Company's claims, the Company will not remain uncompensated for expenditures. However, over recovery is unlikely to ever make its way back into ratepayers' pockets. Indeed, the Commission specifically made note that Consumers could "request any reasonable and prudent spending above the approved project amounts in a future electric rate case" when finding Staff's proposed adjustments based on the same methodology to be reasonable and prudent in Case No. U-21585.[982] This PFD recommends that the Commission adopt Staff's proposed disallowance in this case.

iii. Attorney General Adjustments

Covert Plant

Mr. Coppola testified regarding several proposed disallowances, starting with expenditures at Covert. Mr. Coppola questioned that the Company has projected power generation expenditures of $67.5 million for the bridge period, and $61.4 million in capital expenditures for the plant when the Company only purchased and began operating it in June 2023.[983] Mr. Coppola characterized Consumers' response to inquiries regarding due diligence in acquiring the plant as indicating that future capital investments had been anticipated, but that the Company had not been able to conduct detailed inspections and engineering evaluations until after taking ownership. From this, Mr. Coppola asserted that the purchase had been made without Consumers having done due diligence regarding the condition of equipment and systems, which, if due

[982] March 21, 2025 order in Case No. U-21585, pp. 125-129. Quotation at p. 129.
[983] 3 Tr 2480.

diligence had been done, would have resulted in a lower purchase price.[984] This resulted in customers paying both a high purchase price and for capital upgrades and replacement that the Company wishes to recover through a depreciation expense, allowing Consumers to "effectively receive a return on twice the investment in the same equipment and systems."[985]

Mr. Coppola took specific issue with the Load Commutated Inverter (LCI) Static Frequency Converters (SFC) with a projected expense of $1,305,000 for the bridge period, and $2,610,000 in the projected test year, and with extensive upgrades to the Netmation Operating System to the latest version for $2,922,000 in the bridge period and $8,844,000 in the projected test year.[986] He recommended disallowance of the total $4,227,000 for the bridge period, and $11,454,000 for the projected test year for the two systems, concluding that replacement of these critical systems within two years of purchasing the plant indicates that these issues should have been found during technical due diligence. Additionally, Mr. Coppola believed the Netmation project to still be in an early stage of design and engineering development, with a scheduled completion date in February 2026. As such, he concluded that the project was not sufficiently advanced to be included in rate base in this rate case where cost and timing of the project could still change significantly during the engineering phase.[987]

Mr. Blumenstock initially presented the Covert Plant's gas generating unit availability, the planned outages for the different units, and capacity values, stating that Consumers intends to invest $67.545 million during the 16-month bridge period and

[984] 3 Tr 2480-2481.
[985] 3 Tr 2481.
[986] 3 Tr 2481-2482.
[987] 3 Tr 2481-2482.

$61.443 million at the Covert Plant during the test year.[988] This investment included the spending, as Mr. Coppola noted, for the LCI SFC and the Netmation Operating System and 4S.[989] Mr. Blumenstock characterized the LCI SFC replacements as "required to mitigate the significant risk of failure due to obsolescence," and to "ensure operational reliability" [990] He characterized the Netmation project as an urgent, critical, and extensive upgrade to both the software and hardware of the turbine control system.[991]

In rebuttal, Mr. Blumenstock testified that Consumers "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," and the proposal was uncontested at that time.[992] At the time, the Company projected roughly $67 million of warranty work through 2027, but did not include non-warranty work. However, the acquisition cost of a new plant would have been significantly higher than the Covert purchase, and with the purchase of a previously owned plant there was "an expectation of incremental maintenance to maintain it."[993] Mr. Blumenstock characterized Mr. Coppola's claimed lack of technical due diligence on the Company's part as hyperbole that should be ignored, but conceded that, until the Company was "in a position to operate the plant," it could not assess and evaluate the plant equipment to the same degree as its other, operational plants.[994]

---

[988] 6 Tr 3474-3479, 3513-3514.
[989] 6 Tr 3514, 3517-3518.
[990] 6 Tr 3517-3518.
[991] 6 Tr 3518.
[992] 6 Tr 3598.
[993] 6 Tr 3598.
[994] 6 Tr 3598-3599.

Mr. Blumenstock identified the equipment being replaced for both projects contested by Mr. Coppola as being original to the plant, obsolete, and no longer supported. Failure to replace the equipment threatens plant reliability, while replacement complies with North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) standards regarding "regular updates and maintenance to safeguard control systems."[995] He added that the Company prepared business cases for both projects, found at Exhibits A-46 and A-48.

In her brief, the Attorney General repeats the assertion that the Company did not conduct robust assessments of the Covert plant prior to purchase, and this lack of due diligence left Consumers unaware of the deteriorated condition of the plant's equipment and systems when negotiating its purchase price.[996] From this, she also repeats Mr. Coppola's contention that this results in ratepayers essentially paying twice for capital upgrades and replacements.[997] The Attorney General notes that the LCI SFC is, as the Company acknowledges, a critical component used with gas turbines and related equipment that is at significant risk of failure due to obsolescence; from this, the Attorney General concludes that Consumers should have discovered this during technical due diligence.[998] Similarly, "there is no excuse for the Company failing to discover" the existing issues with the plant's outdated control systems to be resolved by the Netmation upgrades; "the Company should have considered the implication of

[995] 6 Tr 3599.
[996] Attorney General brief, 82.
[997] Attorney General brief, 83.
[998] Attorney General brief, 83.

purchasing a nearly two-decades-old power plant that would have to be overhauled shortly after it was acquired."[999]

The Attorney General repeats the recommendation for disallowance of $4,227,000 for the bridge period, and $11,454,000 for the projected test year for capital expenditures for the two systems on the basis that ratepayers should not bear "the cost of new equipment, system upgrades and replacements" for equipment that should have been deducted from the plant's purchase price, and where the Netmation project is in too early of a design and engineering development phase to be included in rate base.[1000] In recommending disallowance, the Attorney General emphasizes that, when asked to identify what technical due diligence was performed, and what problems were identified, prior to plant purchase, the Company did not provide any specifics. There is no evidence that the equipment being replaced was identified as requiring replacement shortly after the plant was acquired.[1001]

Consumers responds that the Covert plant was thoroughly evaluated prior to purchase, that the acquisition was demonstrated to be both reasonable and prudent, and no party contested the reasonableness or value of the purchase when it was presented in the Company's 2021 IRP case, Case No. U-21090.[1002] That IRP presentation included long-term service agreement (LTSA) capital expenditures of approximately $43 million for 2025 through 2027, and projected LTSA extra work capital expenditure of approximately $24 million; this demonstrated awareness of the additional investments that would be needed at the time the plant was purchased. Furthermore,

---

[999] Attorney General brief, 83-84.
[1000] Attorney General brief, 84-85.
[1001] Attorney General brief, 85.
[1002] Consumers brief, 95-96.

the plant's used condition was factored into the "favorable price" Consumers paid to obtain it.[1003] Consumers' brief also recapitulates Mr. Blumenstock's testimony regarding the necessity of the projects, concluding that the Attorney General's proposed disallowances are unsupported, because both projects are reasonable and necessary investments.[1004]

The Company has provided testimony that the SFC controls and turbine control system are necessary to the functioning of the plant, and that both are in critical need of upgrades and/or replacement.[1005] Furthermore, the Attorney General questions the likelihood of the Company properly estimating and timely completing the Netmation upgrade. However, although the lack of progress beyond the engineering phase is concerning, most of the computer components and software are not described as those needing unique design; as a result, failure to timely complete the project is not inevitable. It is also not inevitable that, even had the need for these capital expenditures been known at the time Consumers purchased the plant, this would have had an impact on the plant's purchase price. For all of these reasons, this PFD recommends against adopting the Attorney General's proposed disallowances.

Ludington Plant

Consumers intends to make capital investments of $15.225 million in the bridge period, and of $13.282 million in the projected test year, in Ludington Pumped Storage (LPS), with Mr. Blumenstock outlining the specific investments.[1006] These include in the bridge period: $2,971,797 for DCS control relay replacement in Ludington Units 1

[1003] Consumers brief, 96.
[1004] Consumers brief, 97.
[1005] 3 Tr 3517-3518.
[1006] 6 Tr 3542-3549, referencing Exhibit A-12, Schedule B-5.2, pages 3, 8, and 9.

through 6; $2,009,804 for the Lower Penstock Expansion Joint (LPEJ) Chamber Waterstop replacement; $2,266,667 for the Ludington 1 pony motor overhaul; $1,287,697 to replace the 480V Dike Load Center (DLC); $1,161,403 for the station water discharge isolation valve; $442,156 for station power transformer life cycle management; $400,010 for replacement of barrier net panels; $303,300 for replacement of the centralized grease system; $487,713 for replacement of all unit critical valve and actuators, and associated equipment; and $1.443 million for fifteen smaller projects.[1007] It also includes $2,026,247 for the "Governor Replacement" in the bridge period.[1008]

The Governor Replacement is also slated for $2,125,719 in the test year. Mr. Blumenstock characterized this as a "contract with a specialized vendor to inspect, repair as required, and modernize the unit governors" which have not be overhauled in 15 years and show significant signs of wear.[1009] Otherwise, the $13,282,000 in capital investment forecasted for the projected test year is comprised of $2,906,676 for DCS control relay replacement; $2,800,000 for the Ludington 1 pony motor overhaul; $1,352,043 to replace 480 V DLCs; $643,137 for Commons Station Power Transformer (SPT) life cycle management; $937,863 intake gate and gate house mechanical replacement; $369,000 to replace barrier net panels; and sixteen additional, smaller projects for a total of $1.542 million.[1010]

Forecasted capital investment also includes $605,621 for the generator potential transformer and enclosure project. Mr. Blumenstock explained that each LPS unit uses six potential transformers (PT) that convert high primary voltage into measurable

[1007] 6 Tr 3543-3546.
[1008] 6 Tr 3544.
[1009] 6 Tr 3544, 3548.
[1010] 6 Tr 3546-3549.

secondary voltage, that these are used for unit metering and regulating, and that there have been unexplainable unit trips due to a “PT Fail” alarm. The alarms, along with visible cracks and other observed signs of aging, particularly considering that the PTs are original to the plant and have surpassed their 20 to 30 year life expectancy, and considering that there are concerns with moisture entry, internal insulating material loss, and corrosion and overheating, have caused the Company to conclude that the PTs could fail, and that they are unlikely to last another 5 to 10 years.[1011] Mr. Blumenstock added that there are three enclosures per unit, with each enclosure housing two PT drawers, and that these have become difficult to open and close due to worn hardware. The enclosures “also create a section of Isophase Phase Bus (IPB),” and create other safety issues, as well as maintenance issues when there are issues with the insert and bolt on the enclosure doors.[1012]

The Attorney General inquired through discovery why Consumers engaged in such large capital spending on equipment and system upgrades only three years after the major overhaul of the six units. Mr. Coppola testified that the Company responded that these expenditures were outside the scope of the original overhaul but provided no evidence in support.[1013] Mr. Coppola questioned why the large capital expenditures projected in this case had not been part of the major overhaul, and he recommended removal of the forecasted bridge period capital expenditures of $15,225,000 and $13,282,000 for the projected test year. He contended that Consumers had “not provided sufficient evidence to justify that the capital upgrades it seeks to recover in this

[1011] 6 Tr 3548-3549.
[1012] 6 Tr 3549.
[1013] 3 Tr 2483-2484.

case are necessary at this time given the recent overhaul of the plant."[1014] The Attorney General's brief makes the same points, and adds that claims by the Company that equipment has degraded since the major overhaul began approximately 10 years ago have not been accompanied by evidence in support.[1015]

In rebuttal, Mr. Blumenstock stresses that the Company's discovery response indicated that the projects for which expenditures are sought in this case were not part of the overhaul and upgrade project, adding that the upgrade project did not "obviate the need for maintenance" and other work.[1016] Mr. Blumenstock characterized the requested total disallowance of capital expenditures for Ludington as arbitrary, unsupported, and absurd, adding that such a disallowance would jeopardize Consumers' ability to maintain its FERC operating license.[1017] He added that there were at least two reasons that the current projects were not included in the overhaul and upgrade. First, the proposed projects were not necessarily needed more than 15 years ago when the overhaul and upgrade project was in development. Second, adding these projects to the overhaul and upgrade would have complicated that project's schedule, likely necessitating longer outage times and resulting in higher costs.[1018] Mr. Blumenstock stated that the Company is not seeking to recover costs for work that was performed during the major overhaul and upgrade, that these are new costs for different

[1014] 3 Tr 2484.
[1015] Attorney General brief, 85-87.
[1016] 6 Tr 3600.
[1017] 6 Tr 3600.
[1018] 6 Tr 3601.

work, and the work outlined in this case does not include corrective work for the overhaul and upgrade project[1019]

Mr. Blumenstock contended that he had provided sufficiently detailed direct testimony to support the major Ludington projects, and that the Company had provided businesses cases for the projects supporting the decisions underlying the projects. He also pointed to Exhibit S-8.0, sponsored by Ms. Maio, noting that Consumers has already spent approximately $3.8 million through June 2025. Mr. Blumenstock concluded that the projects were well supported and necessary to continue safe and reliable operations at Ludington.[1020]

Consumers' brief highlights that Mr. Blumenstock's response to the Attorney General's interrogatories were made under oath; Mr. Blumenstock's sworn statement in discovery had been admitted by the Attorney General as an exhibit, and his testimony and sworn statements constitute evidence in support of the Ludington Pumped Storage projects.[1021] The brief then summarizes Mr. Blumenstock's testimony, asserting that the Attorney General has not provided a valid basis to keep from moving forward with the projects, many of "which are already underway," and that are well-supported and necessary.[1022]

Mr. Blumenstock provided reasonable testimony supporting the expenditures sought for Ludington. The Attorney General does not provide a basis for disallowance beyond conjecture that the major projects should have been part of the overhaul project. Mr. Blumenstock provided two reasons for why these projects were not included, and he

[1019] 6 Tr 3601.
[1020] 6 Tr 3602.
[1021] Staff brief, 97-98.
[1022] Staff brief, 98-99.

has flatly stated that the Company is not seeking compensation for work previously completed. As a result, this PFD recommends allowance of the Ludington capital expenditures.

Campbell Power Plant

In anticipation of plant closure, Consumers has proposed a wastewater treatment system at the Campbell plant and relocation of the plant's machine shop, with $17,782,000 scheduled for the bridge period and $9,600,000 estimated for the projected test year. Mr. Coppola testified that the wastewater treatment system is still in the planning phase of development and should therefore not be included in rate base in this rate case.[1023] He opined that the Company has not completed design or engineering work, and the cost and timeline of the project may change significantly.[1024] As a result, and because it is unclear for how long the plant will be required to operate "under FERC jurisdiction," Mr. Coppola recommended removal of the proposed capital expenditures for both the bridge period and the projected test year.[1025]

Mr. Daly outlined the settlement agreement underlying Campbell's decommissioning.[1026] Mr. Blumenstock clarified that the bridge period capital expenditure for the project is $12.4 million, and not $17.782 million, based on an updated projection.[1027] While agreeing that the Campbell plant's continued operation due to emergency orders from the U.S. Department of Energy will prevent project implementation before the end of the projected test year, the plant's continued operation

[1023] Mr. Coppola's suggestion to open a new docket to review the continued operation of the Campbell plant is discussed elsewhere in this PFD.
[1024] 3 Tr 2486.
[1025] 3 Tr 2486-2487
[1026] 3 Tr 1066-1067.
[1027] 6 Tr 3603.

"delays completion and project closure; it does not stop work for this project."[1028] Mr. Blumenstock contended that the "project is still viable and necessary."[1029] However, given the project's closure status, the Company will offset capital expenditures with AFUDC, removing the impact on the revenue requirement in this case.[1030] Mr. Daly outlined the settlement agreement underlying Campbell's decommissioning in his direct testimony, and Mr. Blumenstock indicated that Mr. Daly's adjusted revenue deficiency reflects the offset of capital expenditures with AFUDC.[1031]

The Attorney General's brief reiterates Mr. Coppola's points, emphasizing that the wastewater treatment system is still in the planning phase, so the cost and timing of the project are likely to change. Continued operation of the plant under DOE orders "makes the timing of proposed work questionable."[1032] Consumers' brief outlines the deep injection well for on-site disposal of ongoing leachate water that is in the permitting process with EGLE and the U.S. EPA, with an NDPDES permit application revision submitted in November 2024. Consumers also outlines the U.S. DOE orders that have continued operations at the plant beyond its scheduled decommissioning.[1033] Consumers has updated the bridge period capital spending to $12.42 million, a reduction from the $17.8 million identified by Mr. Coppola, and admits that continued operations have delayed completion and project closure. But Consumers maintains that it has not stopped work on the project.[1034] To address the anticipated closure of the

[1028] 6 Tr 3603-3604.
[1029] 6 Tr 3604.
[1030] 6 Tr 3604.
[1031] 3 Tr 1066-1067, 1088-1089. 6 Tr 3604-3604.
[1032] Attorney General brief, 89-90.
[1033] Consumers brief, 99-100.
[1034] Consumers brief, 100-101.

project after the test year, the Company is now offsetting the capital expenditure amounts with AFUDC so there is no revenue requirement impact, which is reflected in the updated revenue requirement in Mr. Daly's rebuttal testimony.[1035]

At this time, what future action the DOE will take in relation to Campbell is unclear. While the Attorney General's disallowances may make more sense in a future rate case, depending on the DOE's actions, what the Company is proposing appears to do a better job of maintaining the status quo in the face of uncertainty while still planning for ultimate closure of the plant. This PFD recommends adoption of the reduced $12.42 million bridge period capital spending advanced by Consumers, and the $9.6 million proposed for the test year, with capital expenditure amounts offset by AFUDC to remove the spending from the revenue requirement.

Premature Generation Projects

Mr. Coppola testified that, through discovery, Consumers identified five projects of $3 million or greater that are in the planning phase or that recently entered the design/engineering phase. The Covert plant Netmation program and the Campbell wastewater treatment system have already been addressed, but Mr. Coppola testified that the Covert Spare GSU for $5,910,000, the Zeeland Phase II GT advanced gas path replacement and axial fuel staging for $8,331,000, and the Zealand site spare GSU for $4,481,000, all lacked sufficient certainty. Because it was unclear whether these projects would proceed at the forecasted cost and timeline, Mr. Coppola recommended

[1035] Consumers brief, 100-101.

removal of the $18,722,000 in capital expenditures for these projects from the projected test year.[1036] This is repeated in Staff's brief.[1037]

Mr. Blumenstock responded that the Zeeland spare GSU is in the manufacturing phase, and that, because it is a spare that is to be shipped and stored, manufacturing is the final phase of the project, slated to be completed in April 2026. He asserted that there is no uncertainty and that the project is supported by a business case included in Exhibit A-47.[1038] This testimony is reflected in Consumers' brief.[1039]

In relation to the Covert spare GSU and the Zeeland Phase II gas turbine advanced gas path replacement and axial fuel staging projects (Zeeland Phase II), Mr. Blumenstock stated that both projects had been supported with a business case in response to discovery, neither project was projected to close before the end of the test year, and both projects have been offset with AFUDC so that they have no impact on the revenue requirement in this case.[1040]

Mr. Blumenstock initially testified regarding the Covert spare GSU transformer, explaining the generating station's configuration, and that the turbines transmit their power to the grid via GSU transformers, explaining that, if a GSU were to fail, this would prevent power transmission from the associated turbines, and that lead time for a new GSU is three-to-four years, with spares generally unavailable.[1041] The spare GSU will provide multiple benefits, including greatly reducing unit downtime if a GSU fails, and preventing successive installation of GSU's not designed for the plant until a properly

---

[1036] 3 Tr 2487-2488.
[1037] Staff brief, 90-91.
[1038] 6 Tr 3604-3605.
[1039] Consumers brief, 101-104.
[1040] 6 Tr 3605, citing Exhibits A-198 and A-199.
[1041] 6 Tr 3518.

designed GSU is available. He added that oil analysis of the Covert transformers indicates “chemicals for corrosive sulfur,” which puts the transformers at increased risk of failure while mitigating actions are being taken.[1042]

In relation to Zeeland Phase II, it is intended to increase power output by 51 MW with a 2.5% improvement in heat rate, which has a predicted $45.5 million NPV for customers.[1043] Mr. Blumenstock went on to outline the benefits of the same project that was completed on Zeeland Phase I units, and the improved power output and heat performance from that project, opining that the Zeeland Phase II results should be the same.[1044] Consumers’ brief reflects Mr. Blumenstock’s testimony regarding both the Covert spare GSU and the Zeeland Phase II project, highlights that the projects have been offset with AFUDC so that they have no impact on the Company’s revenue requirement in this case, and asserts that both of these projects will proceed due to their importance and value.[1045]

This PFD credits Mr. Blumenstock’s testimony regarding the certainty and reasonableness of the Zeeland spare GSU and recommends allowance of the capital expenditures for that project. The Covert Spare GSU and the Zeeland Phase II projects present closer questions, as they are not anticipated to close by the end of the test year. However, they are not included in rate base, which is appropriate for projects that will not be completed within the test year. Review of Exhibit A-198 regarding the options considered in relation to the Covert spare GSU, and the losses that are likely to occur if the project is not pursued, and Mr. Blumenstock’s testimony regarding the benefits that

[1042] 6 Tr 3518.
[1043] 6 Tr 3605.
[1044] 6 Tr 3605-3606.
[1045] Consumers brief, 102-104.

are being realized by Zeeland Phase I, and that are likely to be realized by Zeeland Phase II, bolster the Company's representations that the projects are reasonable and prudent, and that they provide enough benefit to the Company that they will be completed. As a result, this PFD recommends approval of the funding over the Attorney General's request for disallowance.

iv. ABATE Adjustments

Ms. York proposed three disallowances in generation capital expenditures. She proposed disallowing $21.163 million for the bridge period, and $13.518 million for the test year for LTSA extra work for Covert. She proposed disallowing $4.703 million for the bridge period, and $0.81 million for the test year, for LTSA extra work at Zeeland. And she proposed disallowing $2.115 million for the bridge period, and $0.315 million for the test year, for LTSA extra work at Jackson.[1046] These will be considered in order.

Covert LTSA Extra Work

Consumers is proposing $12,153,320 capital spending for the bridge period for LTSA extra work at Covert Unit 2. For LTSA extra work at Covert Unit 3, Consumers is proposing $9,009,801 in capital spending for the bridge period, and $4,093,234 for the test year.[1047] Consumers is also proposing Covert Unit 1 LTSA extra work of $9,524,986 for the test year.[1048] Mr. Blumenstock testified that LTSA extras include "the owner's obligations per the LTSA division of responsibility for work performed."[1049] It includes work not covered under normal planned maintenance in the LTSA, which, for Covert Units 2 and 3, are "typical discovery items found on this style of gas turbines" outside of

[1046] 6 Tr 3689-3690.
[1047] 6 Tr 3514-3515, 3519-3520.
[1048] 6 Tr 3519-3520.
[1049] 6 Tr 3519.

the LTSA, including things such as blading, the ammonia delivery system, Selective Catalytic Reduction (SCR) catalyst, turbine rotors, cooling towers, and turbine cooling air cooler.[1050] For Covert Unit 1, they also also include trailer and crane rentals, providing water and bathroom facilities for OEM workers, scaffolding and insulation services, and generator electrical testing.[1051]

Ms. York is recommending disallowance of $21.163 million for LTSA extra work for the bridge period for Covert Units 2 and 3, and she is recommending disallowance of $13.618 million for Units 1 and 3 in the test year.[1052] Although Mr. Blumenstock provided details of the types of issues that might occur as LTSA extra work, Ms. York asserted that these projections are speculative and may not be incurred. Ms. York also stated that they are "out of line with historical actuals," noting that Mr. Blumenstock's workpapers show actual costs in 2023 of $86,688 and $1,339,561 for 2024.[1053] Citing prior Commission orders in support, Ms. York recommended disallowance because the claimed issues to be addressed might not be discovered, thus requiring no spending, and because the historical amounts for LTSA extra work vary greatly each year.[1054]

In rebuttal, Mr. Blumenstock emphasized his direct testimony regarding a planned 59-day major outage at Covert Units 1, 2, and 3 during the bridge period and test year that will include major outage inspections, as well as significant work to be performed during the outage.[1055] In relation to the major inspections, the major inspection of Covert Unit 2 resulted in actual LTSA extra work performed in the amount

---

[1050] 6 Tr 3514-3515.
[1051] 6 Tr 3514-3515, 3519-3521.
[1052] 6 Tr 3692.
[1053] 6 Tr 3693.
[1054] 6 Tr 3693.
[1055] 6 Tr 3514-3515, 3592-3593.

of $12.7 million. Mr. Blumenstock contended that it would be unreasonable to disallow $12.153 million of this on Ms. York's recommendation when the projected capital expenditure ABATE seeks to disallow is already below the actual capital expenditure incurred.[1056]

Mr. Blumenstock further stated that the bulk of the work performed at Covert Unit 2 was within a pre-defined work scope that is the same for all three units, including both repair and emergent work tasks. The Covert Units are identical to one another and have similar operating histories and pre-defined work scope. Because they are likely to incur costs in line with what was actually incurred at Covert Unit 2, Mr. Blumenstock opined that the projected capital expenditures of $13.103 million for Covert Unit 3, and the projected capital expenditures of $9.525 million for Covert Unit 1, were reasonable and should not be disallowed.[1057]

ABATE's brief answers that the work done on Unit 2 may not be representative of the work that will be done on Units 1 and 3, and that the actual costs are highly speculative and may or may not be incurred.[1058] ABATE's brief points to the actual costs incurred in 2023 and 2024, $86,688 and $1,339,561, respectively, to highlight that the currently requested increases are highly speculative and hypothetical.[1059] ABATE also outlines the Commission's findings in Case No. U-21389, and U-21585, concluding that Consumers' evidentiary presentations were inadequate to demonstrate that the projected LTSA extras in those cases were reasonable and prudent.[1060] ABATE

[1056] 6 Tr 3592-3593.
[1057] 6 Tr 3593-3594.
[1058] ABATE brief, 39.
[1059] ABATE brief, 39.
[1060] ABATE brief, 39-40.

contends that Consumers has not rectified the evidentiary deficiencies that resulted in disallowance in prior cases, and advocates for disallowance here. Because this cost category is for unknown issues that might or might not be discovered, and that have no clear historic spending trend, ABATE posits that the proposed capital expenditures are neither reasonable nor prudent and should be disallowed.[1061]

Consumers contends that ABATE's characterization of the Commission's prior findings is false and misleading.[1062] At the time of Case No. U-21389, the Company relied on pre-ownership estimates of LTSA extras costs, and had no historical data, because Consumers had only recently acquired the Covert Plant for its generating fleet.[1063] The Commission remarked on this lack of historical data in both Case Nos. U-21389 and U-21585. However, unlike those cases, Mr. Blumenstock presented the May 25, 2025 major inspection and $12.7 million actual work cost for Covert Unit 2.[1064] He listed the repair and emergent work completed in connection with that Unit. For Unit 2, "[i]t would plainly be unreasonable to disallow the $12.163 million in the bridge period on the grounds that it is 'speculative' or 'out of line with historical actuals' when the bridge period money has already been spent and the historical actuals were $12.7 million."[1065]

Consumers further contends that the bridge period spending for Covert Unit 2 provides the historical data needed to support Covert Units 1 and 3 test year spending because the units are identical, have similar operating histories, and will be subject to

---

[1061] ABATE brief, 40-41.
[1062] Consumers brief, 104.
[1063] Consumers brief, 104-105.
[1064] Consumers brief, 105.
[1065] Consumers brief, 105-106.

the same pre-defined work scope during their planned major inspections; as a result, the projected expenditures in line with those actually incurred for Unit 2 are reasonable and supported.[1066] Consumers adds that the work done to Unit 2 removes the speculative nature about the LTSA extra work that will be performed on Units 1 and 3 in the test year, adding that the major outage inspections have been coordinated with MISO.[1067] ABATE, in its reply brief, points to actual historical experience to counter Consumers' claims that these projections are not unduly speculative.[1068]

At the outset, Consumers has provided testimony that actual spending in relation to Covert Unit 2 exceeds the projected bridge period spending for which the Company seeks approval in this case. As a result, this PFD recommends approval for the projected $12,153,320 capital spending for the bridge period for LTSA extra work at Covert Unit 2. It is documented, not speculative, and already incurred.

In relation to Covert Units 1 and 3, past Commission disallowance of the LTSA extras spending keyed on the lack of historical data used in cost estimation.[1069] Such historical data is still lacking, particularly in relation to Unit 3, where the projected spending exceeds that actually incurred for Covert Unit 2. Review of Exhibit A-191 does not provide historical data. However, we now have actual spending testimony in relation to Covert Unit 2, which is both a similar unit and presented by the Company as similarly operated and maintained. In comparison to the $12.7 million actually incurred for Covert Unit 2, the Covert Unit 1 LTSA extra work projection of $9,524,986 for the projected test year appears reasonable, as it is well under the cost actually incurred for the same work

[1066] Consumers brief, 106.
[1067] Consumers brief, 106-107.
[1068] ABATE reply, 7-8.
[1069] See *e.g.* March 21, 2025 order in Case No. U-21585, pp. 142-149.

at a similar unit in the same plant. As a result, this PFD recommends the allowance of the projected spending for Covert Unit 1 LTSA extra work.

However, this makes the Unit 3 spending projection even more inexplicable, as it appears wholly speculative in comparison to what little historical data ABATE includes in its filings, and in comparison to the Company's testimony regarding actual spending in relation to Unit 2. Based on the spending in relation to Unit 2, Consumers has presented reasonable evidence that at least some projected expenses will be incurred for Unit 3, a similarly situated unit in all respects to Unit 2. However, there has been no reasonable basis presented to believe that the spending on Unit 3 will exceed that for Unit 2. As a result, this PFD recommends approval of the $9,009,801 in capital spending for Unit 3 for the bridge period, and only allowing LTSA extra work capital expense of $3,690,199 for the projected test year. This brings the total allowed amount in line with the Unit 2 capital expenditure of $12.7 million for the same work.

Zeeland LTSA Supplementals

Ms. York recommended disallowance of Zeeland Plant LTSA Supplementals Not Included in Contract in the amount of $4.703 million for the bridge period, and $0.810 million for the test year. She noted that these were speculative projections for issues that might be discovered during the bridge period and projected test year, but that these were out of line with historical actuals.[1070] To this end, she noted that, in 2021 and 2022, the actual cost was approximately $0.5 million; in 2023 it was $15.2 million; and in 2024 it was negative $191,534.[1071] Again, because there was no clear trend in the capital

[1070] 6 Tr 3694.
[1071] 6 Tr 3695.

expenditures, and because the amounts are highly speculative and might not be incurred, she recommended disallowance.[1072] ABATE's brief reflects this testimony, as does its reply brief, which highlights a lack of historical trend to adequately support capital expense projections.[1073] ABATE's brief also highlights the Company's ability to seek cost recovery once actual costs are incurred and known.[1074]

In rebuttal, Mr. Blumenstock pointed out that the Company has revised its projected investments for the bridge period and has reduced the projected bridge period spending from $4.703 million to $2.795 million, and is projecting $0.810 million for the test year.[1075] Mr. Blumenstock listed typical discovery items found in this style of gas turbine, and stated that, if the LTSA extras work is not performed, but equipment remains in use, it could void equipment warranties. Consumers' projections are based on historical outage and work experience, with the Company having invested $0.463 million in 2021, $0.522 million in 2022, $15.184 million in 2023, and nothing in 2024. The lack of spending in 2024 results from the bulk of the work being completed during the Zeeland Phase I Gas Turbine Advanced gas path replacement and axial fuel staging project, which was formally incorporated into the LTSA for 2024.[1076]

Actual capital expenditures for LTSA extra work at Zeeland were $2.120 million through June 2025, resulting in the revised project amount of $2.795 million for the bridge period to better reflect this actual spending. Mr. Blumenstock maintained that this revised bridge period investment of $2.795 and projected test period spending of $0.81

[1072] 6 Tr 3695.
[1073] ABATE brief, 41-42; ABATE reply, 7-8.
[1074] ABATE brief, 42.
[1075] 6 Tr 3595.
[1076] 6 Tr 3595-3596.

million were not highly speculative and were both reasonable and prudent. Consumers' brief repeated much of Mr. Blumenstock's testimony.[1077]

The Commission has previously allowed LTSA extras spending at Zeeland because the cost projections were revised based on actual spending and were based on historical data supporting the requested expenditures.[1078] Furthermore, $2.12 million of the $2.795 million sought in the bridge period has been incurred and presented in testimony. The $0.81 million for the projected test year is not out of keeping with historical spending amounts reflected for 2021 and 2022, reflecting only a modest increase to meet increasing costs. Because the bulk of the bridge period spending has already been incurred, and the projected test year spending is in line with historical spending amounts, this PFD recommends allowance of $2.795 million in capital expense for Zeeland LTSA extras for the bridge period, and $0.81 million for the test year.

Jackson LTSA Extra Work

Ms. York recommended disallowance of LTSA extra work at Jackson in the amount of $2.115 million for the bridge period and $0.315 million for the test year.[1079] She again noted that actual spending had varied, with $4.2 million having been spent in 2021, but less than $0.5 million was spent in 2023 and 2024, and the cost was a negative $180,921 in 2022.[1080] Because there was no clear trend in the capital expenditures, and because the amounts are highly speculative and might not be

[1077] Consumers brief, 107-108.
[1078] March 21, 2025 order in Case No. U-21585, p. 149.
[1079] 6 Tr 3695.
[1080] 6 Tr 3696.

incurred, she recommended disallowance.[1081] ABATE's brief and reply brief reflect Ms. York's testimony, although ABATE's brief highlights the Company's ability to seek cost recovery once actual costs are incurred and known.[1082]

Mr. Blumenstock testified that the Company's capital expenditures for LTSA extra work were $4.192 million in 2021. However, he took issue with Ms. York's assertion that there was a negative cost in 2022; he stated that there was a credit to the 2018 LTSA extra work capital expenditure amount that impacted the 2022 LTSA extra work calculation. Mr. Blumenstock indicated that the actual LTSA extra work capital expenditure for 2022 was $3.92 million. Capital expenditure was $0.497 in 2023 and $0.330 in 2024.[1083]

Mr. Blumenstock testified that the Company increased its projected bridge period spending projection from $2.115 million to $3.472 million, while maintaining the LTSA extra work projection of $0.315 million for the test year. Actual expenditures through June 2025 already totaled $2.758 million, resulting in the updated projection of $3.426 million through September 2025. This is reflected in Staff witness Maio's Exhibit S-8.0.[1084] Mr. Blumenstock's testimony is, in turn, reflected in Consumers' brief.[1085]

The Commission has previously allowed LTSA extra work spending at Jackson because the cost projections were revised based on actual spending and were based on historical data supporting the requested expenditures.[1086] The originally projected test year and bridge period spending is within historical norms, and actual bridge period

---

[1081] 6 Tr 3696.
[10821082] ABATE brief, 42-43. ABATE reply, 7-8.
[1083] 6 Tr 3596-3597.
[1084] 6 Tr 3597.
[1085] Consumers brief, 109-110.
[1086] March 21, 2025 order in Case No. U-21585, p. 149.

spending has already surpassed the projected spending in that year. Nevertheless, because the increase in the bridge period projection amount is coming at a late stage of the case, potentially depriving intervenors of an opportunity to reasonably object to the increased amount, and because documentation of increased spending is thin, this PFD recommends that only the $2.115 million originally filed for the bridge period, and the $0.315 million for the test year, be approved.

v. MNSC Adjustments and Other Recommendations

Mr. Blumenstock testified that Consumers intends to invest $24.489 million in the 16-month bridge period in the Jackson plant (Jackson), and projects capital spending of $28.143 million in the test year.[1087] This spending includes $1,333,333 for the bridge period, and $2,333,334 for the test year, for the GSU Transformer Site Spare, a project that would provide a spare transformer in the case of failure, with lost generation estimated to be 47 MW to 104 MW, and current replacement time being 3-4 years.[1088] It also includes $646,911 for the bridge period, and $960,102 for the test year, for the JLM1-6 VIGV project, to install six new VIGV systems on six engines at the Jackson plant, with a seventh partial installation already in process. Mr. Blumenstock testified that this project is anticipated to yield significant fuel efficiency improvements.[1089]

Tyler Comings, a principal economist at Applied Economics Clinic, testified on behalf of MEC and CUB.[1090] He noted that Consumers has three natural gas combined cycle (NGCC) power plants in its fleet: Covert, slated to run until 2040, and Jackson and

[1087] 6 Tr 3536-3542, citing Exhibit A-12, Schedule B-5.2.
[1088] 6 Tr 3537, 3539-3540.
[1089] 6 Tr 3537, 3540.
[1090] 6 Tr 3880.

Zeeland, both slated to run until 2041.[1091] Of these, he opined that Jackson is the least efficient and most expensive to run (not including the combustion turbines at Zeeland), and that it was the most vulnerable to risk, such as natural gas prices and stranded costs.[1092]

Outlining gas price risk for gas plant operators, Mr. Comings concluded that Consumers' net energy value (NEV) for the Jackson plant for 2020 through 2024 is overstated.[1093] He testified that heat rate of a plant or unit is an important factor in measuring the efficiency of converting fuel to electricity, and that Jackson's heat rate is roughly 15 percent higher than Covert and Zeeland, requiring 15% more fuel to produce a unit of power, and resulting in the highest fuel costs of the three NGCC plants.[1094] It also makes Jackson more vulnerable to gas price increases than typical NGCC.[1095]

Mr. Comings further testified that, because Jackson is the "most economically vulnerable of the three NGCC plants … further investment in the plant should be carefully considered."[1096] He indicated that he was not advocating for retirement of Jackson, but went on to explain that generating plants that are retired earlier than planned can leave capital costs unrecovered, or recovered through accelerating depreciation, using a regulatory asset after retirement, or securitizing the unrecovered amount for recovery after retirement, and Jackson may be at risk of this if it ultimately becomes uneconomic to run. As a result, Mr. Comings concluded that two capital projects should be disallowed as unsupported or flawed, after outlining his review of

---

[1091] 6 Tr 3883-3884.
[1092] 6 Tr 3884.
[1093] 6 Tr 3884-3887, 3889-3890.
[1094] 6 Tr 3887-3890.
[1095] 6 Tr 3890-3891.
[1096] 6 Tr 3891.

capital projects at the NGCC plants in general and Consumers' economic assessments of projects.[1097] Specifically, in relation to the Company's economic assessments, he questioned the Company's input assumptions in its modeling, including the length of an outage, the capacity that is affected by the outage, wholesale energy prices, variable costs, timing of the outage, heat rate improvement or capacity improvement or de-rate, all of which can lead to estimates that are not reasonable if the inputs themselves are unreasonable.[1098]

Recommended Adjustments

Mr. Comings recommended disallowance of the JGS-Generator Step Up Transformer (GSU) Site Spare, with projected costs of $1.33 million in the bridge period and $2.33 million in the projected test period.[1099] He also recommended disallowance of the Jackson Plant LMI1-6 variable inlet guide vane (VIGV), with "$7,885 in the historic test period, $646,911 in the bridge period, and $960,102 in the projected test period."[1100] Both projects were approved in Case No. U-21585, and Mr. Comings represented that he is only recommending disallowance of incremental costs in this case, not the prior allowance.[1101]

In relation to the spare GSU project, Mr. Comings opined that the potential outage energy value during a potential outage was overstated. He questioned the capacity factor input, because plant operations have been between 31 and 39 percent in the past five years, which is lower than the Company's economic assessment. He

[1097] 6 Tr 3891-3895.
[1098] 6 Tr 3894-3895.
[1099] 6 Tr 3895.
[1100] 6 Tr 3895-3896.
[1101] 6 Tr 3895-3896.

also believed that the assumed level of de-rate was too high, and that the plant could produce more energy than assumed by the Company in the event of a failure due to the Company assuming a worst-case scenario.[1102] Mr. Comings also calculated that capacity value during a potential outage to be overstated, noting that the Company assumes maximum nameplate capacity in its calculation.[1103] This was in comparison to the Company's estimate that there would be a 5% chance of failure leading to power loss, increasing by 5 percentage points each year, without the project, but the value of the project assumes 100% certainty of a failure occurring.[1104]

As a result, Mr. Comings surmised that the combined assumptions regarding capacity factor, level of derate, and failure to include the low probability of failure, resulted in an overstatement of the energy value. He calculated a capacity value loss of only $1.3 million in comparison to the $28 million claimed by Consumers.[1105] He recommended disallowance of the $3.66 million bridge and test period costs for the project.[1106] To Mr. Comings, Consumers' benefit calculation was overstated and highly speculative versus well known costs, resulting in project approval based on a skewed view of potential benefits.[1107]

In relation to the VIGV project, Mr. Comings took the position that the Company's estimates of avoided repairs, fuel savings and increased energy value from the project were inadequate support for the project. The Company provided the energy value of the upgrade as $29.6 million based on the Aurora model, but it did not provide a workbook

---

[1102] 6 Tr 3896-3897.
[1103] 6 Tr 3898.
[1104] 6 Tr 3897.
[1105] 6 Tr 3897-3898.
[1106] 6 Tr 3896-3898
[1107] 6 Tr 3898.

or the source of the derivation of the calculations. In fact, Consumers verified that these did not exist. Mr. Comings recommended disallowance of $1.61 million in capital costs for the project based on the lack of support provided.[1108]

Mr. Comings also expressed concerns with the economic analysis for the 1-6 Feedwater Desuperheater Valve project, and the Zeeland Plant Phase I Gas Turbine Upgrades, but did not recommend disallowance for either project.[1109] He indicated that the underlying calculations for energy value for projects should be explicitly shown. He also asserted that the Company should provide access to any models used.[1110]

Mr. Blumenstock responded that both the GSU Transformer Site Spare and VIGV projects were approved in Case No. U-21585. The prior approval constituted $916,667 of the $3,666,667 for the spare GSU, and $1,036,667 of the $1,614,698 for the VIGV project. As a result, the maximum amounts that could be disallowed in this case should subtract the prior approvals.[1111] Because $916,667 of the $3.66 million in bridge and test period spending has already been approved, the Company contends that the maximum disallowance amount for the project can only be $2.75 million.[1112] According to Mr. Blumenstock, the projects had progressed based on the prior approval "in good faith."[1113]

The Company generally agreed that the capacity factor used in the calculation for the spare GSU was between 65% and 84%, while historical plant operations have been between 31% and 39% due to nitrogen oxide emission limitations limiting dispatch and

---

[1108] 6 Tr 3899, 3901.
[1109] 6 Tr 3899-3900.
[1110] 6 Tr 3900.
[1111] 6 Tr 3617, 3619-3620.
[1112] 6 Tr 3619.
[1113] 6 Tr 3616-3617.

operating hours.[1114] However, Mr. Blumenstock disagreed regarding Mr. Comings' asserted derate of 47 MW; engineering review with plant operations indicated that the 47 MW de-rate was not physically possible. Instead, Mr. Blumenstock indicated that if a GSU fails, both LM units tied to the transformer must come offline, and isolation of a single LM is not possible. Therefore, the conservative derate is approximately 104MW based on the loss of two LM units and the associated loss of steam generation.[1115]

Similarly, Mr. Blumenstock responded that no disallowance is warranted in relation to the VIGV project, but that, if any amount is disallowed, due to approval of $1,036,667 in Case No. U-21585, any disallowance should be no greater than $578,031.[1116] Addressing Mr. Comings' other testimony, Mr. Blumenstock described what was provided to represent the Company's systematic and conservative approach to quantifying project risks where the hard-coded calculations from use of the Copperleaf modeling tool were not available [discussed in greater detail, *infra*].[1117] Mr. Blumenstock also clarified that the Company only includes variable costs directly attributable to operating a unit, such as chemical reagent costs, when calculating NEV. And he took the position that the economics of the Jackson Generating Station in comparison to other gas generating sites would be more appropriately considered in Consumers 2026 IRP.[1118]

MNSC's brief largely summarizes Mr. Comings' testimony, emphasizing in relation to the GSU transformer project that the inaccurate capacity factor and

---

[1114] 6 Tr 3617.
[1115] 6 Tr 3617-3618.
[1116] 6 Tr 3620.
[1117] 6 Tr 3621.
[1118] 6 Tr 3622.

probability of failure to existing equipment used with the Aurora computer model skewed the results to overstate the benefit portion of the benefit cost analysis.[1119] MNSC maintains Mr. Comings' derate assumption, and notes Mr. Blumenstock's agreement regarding the capacity factor assumption. MNSC otherwise summarizes Mr. Blumenstock's rebuttal testimony, touching on the fact that portions of the rebuttal testimony were stricken due to introducing new analyses.[1120]

In relation to the VIGV project, installing equipment to improve plant efficiency and performance, MNSC asserts that the estimates of avoided repair costs and fuel savings, in addition to the increased energy value from assumed efficiency gain, were again based on the conceded inaccurate capacity factor used in the Aurora model.[1121] As a result of the shortcomings in Consumers' underlying benefit estimates as outlined by Mr. Comings, coupled with the lack of comprehensive response, MNSC recommended that the two disallowances be adopted.[1122]

In answer to Consumers' claims that MNSC is seeking to disallow previously allowed amounts, MNSC argues that the amounts previously allowed for the projects in Case No. U-21585 are not part of the $3.67 million Mr. Comings proposes for disallowance in relation to the GSU Transformer project. MNSC further asserts that the $1,614,898 disallowance recommended for the VIGV project does not include the $1,036,667 approved spending from the prior rate case, repeating that only incremental spending is recommended to be disallowed.[1123] In response to arguments that

---

[1119] MNSC brief, 13-16.
[1120] MNSC brief, 16.
[1121] MNSC brief, 17-18.
[1122] MNSC brief, 13-16, 19.
[1123] MNSC brief, 16-19.

economics belong in an IRP, MNSC notes that Mr. Comings stated that he was expressing concern that the Jackson plant is economically vulnerable, but that he was not recommending its retirement. MNSC concludes by recommending disallowance of $5.28 million in relation to the test and bridge periods for the GSU spare transformer and VGIV projects.[1124]

Consumers' brief summarizes the relevant testimony, stressing that related to the reasonableness of the contested projects.[1125] The Company contends that the Commission should reject Mr. Comings' proposed disallowances because both projects have been supported by appropriate evidence. As will be discussed, *infra,* Consumers adds that Mr. Comings' recommendation regarding transparency is unnecessary.[1126] Consumers emphasizes that both contested projects were found to have value and were approved in Case No. U-21585.

From this, Consumers takes the position that, under *Pennwalt Corp v PSC,* 166 Mich App 1, 9; 420 NW2d 156 (1988), the reasonableness of the costs approved in a prior rate case do not need to be "completed relitigated" in a subsequent rate proceeding, instead placing the burden on the challenging party by new evidence or changed circumstances, to establish that the costs were unreasonable.[1127] According to Consumers, the prior allowance of the projects in the prior rate case indicates that the Commission found the projects to be "beneficial to customers and well justified."[1128] To revisit the reasonableness of the projects, given their past allowance, Consumers

---

[1124] MNSC brief, 19.
[1125] Consumers brief, 110-117.
[1126] Consumers brief, 110-111.
[1127] Consumers brief, 113-114.
[1128] Consumers brief, 113.

asserts that Mr. Comings had to provide new evidence demonstrating that the projects are unreasonable, and MNSC has not made such a demonstration. As such, it would be "unreasonable to defund projects that are underway before they are completed, at significant risk of increased costs to customers from failure to complete these projects, based on Mr. Comings speculative and improbable concerns about the full degree of benefits relative to the low cost of the projects."[1129]

Consumers asserts that MNSC is not simply challenging incremental expenditures to complete the two projects but instead is challenging whether either project was ever appropriately justified, which Consumers contends was decided in the prior rate case. Because MNSC has not provided new evidence or a change in circumstances, the recommended disallowances should not be permitted. According to the Company, Mr. Comings has also not provided updated analyses that would carry the burden of proof under *Pennwalt*.[1130] "At most, Mr. Comings provided new evidence that attempts to create the perception that the original benefit-cost determination was inconclusive," which is insufficient under *Pennwalt.*[1131] In the absence of new evidence, the original approval of the projects remains reasonable where the cost benefit analyses were highly favorable of the projects in the first place.[1132]

Furthermore, in the Company's view, in the absence of new evidence, and particularly in relation to the VIGV project where the primary complaint is the lack of a workbook showing the derivation of the underlying calculations, the comfortable margin of the cost benefit analyses for the projects with their original assumptions should carry

[1129] Consumers brief, 117.
[1130] Consumers brief, 113-117.
[1131] Consumers brief, 114.
[1132] Consumers brief, 114-115.

the day.[1133] In support, Consumers notes that the spare GSU projects have been favorably viewed for both Covert and Zeeland.[1134] Consumers also reiterates its position that the disallowances include amounts already approved in Case No. U-21585, so the maximum appropriate disallowance for the VIGV project is only $578,031, and $2.75 million for the Jackson spare GSU.[1135]

MNSC's reply brief first responds that *Pennwalt* does not apply in this case. MNSC asserts that it is not questioning the inclusion of the contested projects from a prior case; the projects were approved without objection and were not actively litigated, thereby distinguishing MNSC's request from *Pennwalt.*[1136] Next, MNSC acknowledges that Mr. Comings identified defects in Consumers' economic analyses for the two projects, but, otherwise, MNSC denies that he had to perform analyses establishing that the defects were outcome determinative. MNSC responds that Consumers bears the burden of proof by a preponderance of the evidence.[1137]

MNSC properly states the burden of proof in a rate case. And MNSC properly asserts that this scenario is not the contested case contemplated by *Pennwalt.* That said, it is troubling, particularly in relation to the VIGV project that is well under way at a relatively low cost, to question project reasonableness in so short a time after approval of the projects in a prior rate case. Because the VIGV project is already being installed, and Consumers has provided evidence that the project is expected to provide

---

[1133] Consumers brief, 115-116.
[1134] Consumers brief, 116.
[1135] Consumers brief, 117.
[1136] MNSC reply, 3-4.
[1137] MNSC reply, 3-4.

substantial fuel efficiency improvements,[1138] albeit based on economic analyses that were somewhat flawed, this PFD is reluctant to pull the plug at this time and recommends funding for this project be approved. Similarly, Consumers has provided credible testimony that, while the capacity factor used in the calculation was wrong, its derate for the spare GSU was more accurate. The plant is currently set to run until 2041, with the likelihood of a GSU failing growing year-over-year, even if it has a relatively low likelihood of failure at present. The Company's testimony regarding the potential derate in the event of a failure is also compelling. In light of up to a 3 year delay to order a new GSU, and the losses at Jackson that would result without a spare GSU on hand if an existing unit fails, this PFD recommends full allowance of the amounts requested in this case.

Transparency Issues

At the conclusion of his testimony, Mr. Comings indicated that, if Consumers calculates energy value for a project, they need to provide the underlying calculations with the final estimate. Even separate workbooks that Consumers provided showed underlying calculations limited by hard-coded model outputs. Mr. Comings recommended that Consumers "should provide the maximum level of transparency, including providing access to any model used."[1139]

Mr. Blumenstock explained that the calculations contained in the economic modeling tool it uses for generation projects, Copperleaf, are hard-coded, meaning that they are embedded in the software and cannot be downloaded to a report or a

[1138] 6 Tr 3540.
[1139] 6 Tr 3900.

spreadsheet. Instead, Consumers provided a procedure in response to discovery that has been developed to explain the assumptions made in each risk model, along with examples of how the calculations are made for the Company's two most used models.[1140] Mr. Blumenstock represented that he had included Consumers' Copperleaf procedure as Exhibit A-205, and the Company had provided discovery including PSCR case values that are direct inputs for the models. He opined that what had been provided should be sufficient to demonstrate its employment of a systematic and conservative approach to quantifying project risks.[1141]

In its brief, Consumers characterizes MNSC's transparency recommendation as unnecessary. The Company contends that MNSC never asked for access to the models used by the Company, and that this could have been provided upon request.[1142] Consumers further explains that the situation with the hard-coded calculations involves inputting assumptions, such as heat rates, unit capacity, and duration of outage, and the software calculates output, with Consumers citing dollar value of lost energy production as an example. Consumers analogizes this to an online mortgage calculator, where a user inputs a hypothetical downpayment, interest rate, and term of loan to obtain an estimated monthly payment amount.[1143] Because the calculations are hard-coded and are not available, Consumers provided a procedure in response to discovery explaining the assumptions made in each risk model and providing examples of how the calculations are made for its two most used models, as well as PSCR case values that are direct inputs for the models. Consumers indicates that "[t]here is nothing more that

[1140] 6 Tr 3621.
[1141] 6 Tr 3621.
[1142] Consumers brief, 117-118.
[1143] Consumers brief, 118-119.

the Company could have provided."[1144] Had MNSC requested access to the software, it could have tested the "software's results using known control inputs," but no such request was made.[1145] Consumers asserts that it was as transparent as possible.[1146]

The Company cannot be required to provide calculations that do not exist. However, to the extent that calculations exist, these should be provided for review, along with the procedure explaining the underlying assumptions used in the Company's modeling. Additionally, having now heard the Company's claims that MNSC did not ask for access to the model, which is why it was not provided, it seems likely that MNSC will be asking for access to the model from now on. This PFD recommends that Consumers be as transparent as possible going forward, but finds there is no basis to require the Company to provide calculations that do not exist.

Preservation of Evidentiary Issue

On October 23, 2025, Michigan Environmental Council filed a Motion to Strike portions of Mr. Blumenstock's rebuttal testimony directed at rebutting Mr. Comings, and also seeking to strike Exhibits A-202 and A-203. The motion was granted November 7, 2025 following a November 4, 2025 hearing and a request for supplemental briefing. In its case brief, Consumers discusses the motion to strike and its being granted on November 7, 2025.[1147] Consumers maintains that the decision to strike the testimony and exhibits as requested was erroneous, that the opinions cited in support were inapposite or inappropriately applied, and that the contested material should have been

[1144] Consumers brief, 118-119.
[1145] Consumers brief, 119.
[1146] Consumers brief, 119.
[1147] Consumers brief, 119-120.

admitted into evidence. “Consumers Energy preserves its right to argue so before the Commission in later briefing in this case.”[1148]

Review of the docket does not reveal an appeal of the motion to strike. The subject matter addressed in the motion to strike is outside the scope of Consumers’ January 6, 2026 Application for Leave to Appeal the denial of the Company’s motion to exceed the page limit set for reply briefs in this case. And the topic does not appear to have been included in the Company’s stricken brief that was filed on December 23, 2025. The content of the motion to strike also appears to be outside the scope of the Commission’s January 15, 2026 order granting the petitions for rehearing by the Attorney General and MNSC regarding the wording of the September 5, 2025 amended scheduling memo relating to ROE.[1149]

As a result, it is unclear why Consumers wishes to preserve the stricken testimony for “later briefing.”[1150] However, the Company’s reservation is duly noted. Insofar as this reservation is not accompanied by further legal argument or action, no further action is required in this PFD.

c. Hydroelectric Generation

Mr. Blumenstock testified that the River Hydro units are to be operated in compliance with their FERC project licenses as the Company generates retirement and decommissioning analysis for each facility. He added that Consumers is not presenting any capital investments for River Hydro in this case, having received approval in Case No. U-21585 for use of a deferred regulatory accounting, adding that it is the

[1148] Consumers brief, 120.
[1149] January 15, 2026 order in Case No. U-21870.
[1150] Consumers brief, 120.

Company's intention to seek recovery in a future regulatory proceeding.[1151] Mr. Blumenstock also outlined the RFP for river hydro divestiture, the possible path of river hydro divestiture, and the value of the river hydro units in the meantime.[1152] In its brief, Consumers reiterates that there are no capital investments for river hydro units being sought in this case, and the Company requests that continuation of the deferred accounting approved in Case No. U-21585, noting that this continuation is unopposed.[1153] Without any apparent opposition, this PFD recommends continuation of the deferred regulatory accounting approved in Case No. U-21585 in relation to the river hydroelectric generation capital expenditures.

d. Battery Storage

Mr. Clark presented the Company's capital expenditures associated with new Battery Energy Storage System ("BESS") projects, specifically the Iosco BESS Project and the Weadock BESS Project.[1154] Mr. Clark stated that the Iosco BESS and Weadock BESS projects associated capital spending supported in his testimony are a subset of the overall generation capital expenditure plan explained and sponsored by Company witness Blumenstock.[1155] Mr. Clark provided an overview of the Company's IRP BESS 75 MW Deployment program, noting that in Case No. U-21090, the Company's 2021 IRP, and corresponding Settlement Agreement, dated June 23, 2022, the Company

[1151] 6 Tr 3479-3481.
[1152] 6 Tr 3481-3484.
[1153] Consumers brief, 120-121.
[1154] 3 Tr 972.
[1155] 3 Tr 973.

agreed to add 75 MW of battery capacity between 2024 and 2027.[1156] He then reviewed the requirements for the Company's battery deployment program.[1157]

Mr. Clark stated that the Company conducted customer outreach, identified two specific project sites, issued two battery deployment solicitations, evaluated the proposals, executed all necessary contracts and procurements, and began the design process for both projects, which were presented in the Company's 2024 Electric Rate Case.[1158]

Turning to the Weadock BESS Project, Mr. Clark described as a 45 MW/180 MWh lithium-ion battery energy storage system interconnected at the Weadock Substation on the Company's 46 kV high voltage distribution system located in Bay County. He stated that the purpose of this project was to provide localized grid support and provide data regarding how battery storage could benefit the reliability, resiliency, and performance of the high voltage distribution system, as well as provide energy arbitrage and firm dispatchable capacity in the MISO market. This project would be constructed on Company-owned property within the Karn/Weadock Generating complex. Mr. Clark testified that the project has been executed utilizing Major Procurement Agreements for Engineering, Procurement, and Construction ("EPC"); Substation Transformer Unit Agreement; and Battery Supply Agreements ("BSAs")[1159] and is scheduled to begin commercial operation on December 21, 2026.[1160]

[1156] 3 Tr 974.
[1157] 3 Tr 974.
[1158] 3 Tr 975-76.
[1159] Conf Exhibits A-55, A-56, A-58; Exhibit A-57.
[1160] 3 Tr 976.

Mr. Clark testified that there was one significant change to the contracts in that Energy Vault, Inc. ("Energy Vault") would assume the BSA previously executed with Our Next Energy. Energy Vault has agreed to all terms and conditions of the BSA, except as explicitly stated in Contract Change Order #1.[1161] Our Next Energy was unable to provide sufficient project financial risk mitigation, as required under the terms of the BSA; however, Mr. Clark noted the Company evaluated Energy Vault's financial risk and determined that they were well positioned to address the issues present with Our Next Energy.[1162]

Mr. Clark testified that the Company projects that it will spend $40,560,000 in the Bridge Period and $14,930,000 in the Test Year, bringing the total projected capital expenditures for the Weadock BESS project to $67,450,000. These values are estimated based on the executed Substation Transformer Agreement, BSA, and EPC Contract, along with the Company-approved overheads and loadings.[1163] Mr. Clark noted the increased project costs provide a more precise reflection of project costs and loadings based on the current commercial operation dates.[1164]

Addressing the Iosco BESS project, Mr. Clark stated that project was a 30 MW/120 MWh lithium-ion battery energy storage system interconnected at the Iosco Substation on the Company's 46 kV high voltage distribution system located near the City of Oscoda, Iosco County. The purpose of this project is to provide localized grid support and provide data regarding how battery storage could benefit the reliability,

---

[1161] 3 Tr 977; Conf Exhibit A-59.
[1162] 3 Tr 977.
[1163] 3 Tr 978.
[1164] 3 Tr 978.

resiliency, and performance of the HVD system as well as provide energy arbitrage and firm dispatchable capacity in the MISO market. He noted this project would be constructed on existing Company-owned property near the existing Iosco Substation. The project has been executed utilizing Major Procurement Agreements for EPC; Substation Transformer Unit; and BSA.[1165] Mr. Clark stated that the Iosco BESS Project was scheduled to begin commercial operation on December 21, 2026.[1166]

As with the Weadock BESS, Mr. Clark stated that Energy Vault, Inc. would assume the BSA for the Iosco BESS previously executed with Our Next Energy. Energy Vault has agreed to all terms and conditions of the BSA, except as explicitly stated in Contract Change Order #1.[1167] Mr. Clark noted the Company projects that it would spend $30,050,000 in the Bridge Period, $11,460,000 in the Test Year bringing the total projected capital expenditures to $49,900,000. These values are estimated based on the executed Substation Transformer Agreement, BSA, and EPC Contract, along with the Company-approved overheads and loadings.[1168] The project costs were revised and updated based on the current commercial operation dates.[1169]

Ms. Champion presented Staff's review and recommendations regarding the Company's two proposed energy storage projects and their accompanying contracts.[1170] She noted that both projects had a 20-year design life.[1171] Ms. Champion explained that the Company has several previously approved storage projects, but

---

[1165] 3 Tr 978-79; Conf Exhibits A-61 to A-64.
[1166] 3 Tr 979.
[1167] 3 Tr 979; Conf Exhibit A-65.
[1168] 3 Tr 980.
[1169] 3 Tr 980.
[1170] 6 Tr 4262.
[1171] 6 Tr 4262-63.

these projects are all significantly larger than the two projects presented in this case. The previous projects and IRP proxy LCOS values were approximately $145/MWh, roughly $50/MWh less than the two proposed projects.[1172] Lazard Inc., a financial advisory and asset management firm, conducts an annual analysis of energy generating technologies, the Levelized Cost of Energy+ Report. Included in this report was an analysis of LCOS for energy storage resources. The closest category to the two proposed projects was the Utility-Scale Standalone (100 MW, 4-Hour) category with LCOS ranges from $115/MWh to $254/MWh. Both Weadock and Iosco fall within that range of LCOS values.[1173] Ms. Champion noted that the two projects combined would align with the June 23, 2022, settlement agreement.[1174] Ms. Champion also reviewed the contracts for the two storage projects and recommended the Commission approve them as consistent with the Company's approved IRP settlement agreement with a cost in the expected range.[1175]

In its brief, the Company reiterates Mr. Clark's testimony and notes that no witnesses presented evidence opposing the Company's BESS project investments in this case. Therefore, the Company asserts that its planned investments for these projects are reasonable and prudent and should be approved in this case.[1176]

In its brief, Staff reiterates Company testimony on the two BESS projects and associated contracts and recommends the Commission approve the Weadock and

---

[1172] Conf 6 Tr 4287.
[1173] 6 Tr 4263-64.
[1174] 6 Tr 4264.
[1175] 6 Tr 4264.
[1176] Company brief, pp. 121-23.

Iosco Battery Energy Storage System projects,[1177] noting that these projects are consistent with the Settlement Agreement in Case No. U-21090, where the Company agreed to add 75 MW of battery capacity between 2024 and 2027.

No contrary evidence was presented; therefore, this PFD recommends the Commission approve these projects as presented.

e. Decommissioning and Coal Ash Disposal

Mr. Koetje presented the actual 2024 expenses for D.E. Karn ("Karn") Units 1 and 2 and J. H. Campbell ("Campbell") Units 1, 2, and 3 decommissioning, and the actual 2024 coal ash disposal costs for those units plus the Classic 7 units.[1178] He also presented updated projected decommissioning expenses for Campbell Units 1, 2, and 3, consistent with the projection presented in Case No. U-21585, as well as updated projected decommissioning expenses for Karn Units 1 and 2 between 2025 and 2026.[1179] Specifically, Mr. Koetje testified that the 2024 decommissioning costs for Karn Units 1 and 2 were $21,294,185, while total actual and forecasted costs were projected to be $77,319,077 (a decrease of $13,208,533 from the total project costs presented in Case No. U-21585).[1180] Regarding Campbell Units 1, 2, and 3, Mr. Koetje testified that 2024 decommissioning costs were $5,243,744, while the current estimate for the complete decommissioning of those units is $380,000,000 (an increase of $64,000,000 from the estimate provided in Case No. U-21585).[1181] He stated that total 2024 coal ash

---

[1177] Staff brief, pp. 199-200.
[1178] 3 Tr 1628.
[1179] 3 Tr 1628.
[1180] 3 Tr 1634-1635; see Exhibit A-139.
[1181] 3 Tr 1648-1650; see Exhibit A-141. In footnote 2 at 3 Tr 1648, Mr. Koetje stated that on May 23, 2025, the U.S. Department of Energy (DOE) issued an order requiring the Company to "take all measures necessary to ensure that the Campbell Plan [sic] is available to operate" through August 21, 2025. He

disposal costs were $52,146,763 and that the projected disposal costs had not changed from the Company's previous filing.[1182] Mr. Koetje further testified that the Commission previously approved regulatory asset treatment for these expenses, as more fully discussed by Mr. Daly.[1183]

4. Facilities Capital Expenditures

a. Control/Dispatch Center(s)

Mr. Guinn stated that the Control/Dispatch Center Consolidation Project – Grand Rapids, and the Control/Dispatch Center Consolidation Project -Parnall Road, are both in the design phase, and Consumers is projecting $10,746,000 for the combined consolidation project renovations in the bridge period and $15,497,000 for the test year. Mr. Snider testified that in 2004 Consumers incurred $3.4 million in costs for the Control/Dispatch Center Consolidation project for design services, material acquisition, and initial space renovations 2024.[1184] Consumers initially planned one fully staffed control center with an unstaffed back-up facility, which was anticipated to yield $8.6 million in annual savings and a SAIDI reduction of 15 minutes, and that had an estimated project cost of $17.2 million between 2023 and 2026.[1185] However, Consumers changed the scope of the Control/Dispatch Center Consolidation to staff the Grand Rapids back-up location. This was done after determining through employee

---

stated that the Company is evaluating the impact of the DOE Order on its decommissioning plan and that until the Company completes its evaluation, his testimony "continues to reflect assumptions about the Campbell Plant's retirement before the date of the DOE Order."

[1182] 3 Tr 1643-1644, 1647; see Exhibit A-140.

[1183] 3 Tr 1629, 1632, 1649; see also 3 Tr 1066-1067.

[1184] 3 Tr 2165.

[1185] 3 Tr 2159-2160.

feedback that staffing would enhance operational capabilities, and that there was otherwise "a risk of losing talent."[1186]

Mr. Snider stated that the staffed Grand Rapids back-up location "provides a better level of service and equitable cost avoidance, and SAIDI savings."[1187] The two fully staffed control centers are anticipated to yield annual savings of $10.2 million and SAIDI reduction of 20.8 minutes by March 2028. The total project cost and implementation is projected to be $30.7 million, with capital expenditures for the two fully staffed control centers estimated at $30.6 million, $15.8 million of which is projected for the test year, with a project schedule running from 2023 to the first quarter of 2027.[1188] According to Mr. Snider, two fully staffed facilities ensure redundancy and enhance resilience, as well as "maximize the benefits of improved resource allocation and operational efficiency," with the projected benefits set forth in Figures 7 and 8 in Mr. Snider's testimony.[1189]

Mr. Snider grouped the milestones for the project into building and facilities, and he outlined both. Process efficiencies should result in expanding the Jackson facility's operations from 16 hours per day, five days per week, to round-the-clock coverage. And resource preparedness merged three operating groups into two, high voltage distribution and low voltage distribution, while redistributing tasks and roles to produce a smoother workflow.[1190] Mr. Snider stated that the consolidation project avoided $2.483 million in service restoration costs, reduced grid operations labor costs by $0.9 million,

---

[1186] 3 Tr 2157-2158.
[1187] 3 Tr 2158.
[1188] 3 Tr 2160, 2162-2166.
[1189] 3 Tr 2161.
[1190] 3 Tr 2160.

and reduced all-weather SAIDI by 4.1 minutes through enhanced storm readiness and fewer ICS responder activations in 2024. From this, Mr. Snider presented the continued cost and benefit projections of the project going forward, with benefits being realized by "operational efficiencies" and increased use of technology.[1191] He indicated that the projected benefits in this case have been adjusted from those projected in Case Nos. U-21389 and U-21585 based on refined historical data from 2022 to 2023, and from the benefits realized in 2024.[1192]

Mr. Coppola testified that Exhibit A-12, Schedule B-5.6 shows the forecasted $23.7 million for the bridge period and $27.4 million for the projected test year for all Asset Preservation under Facilities and Shared Services, adding that lines 25 and 26 of page 1 of Exhibit A-102 show historical and forecasted capital expenditures for the Grand Rapids and Parnall Road dispatch centers.[1193] In addition to noting the Company's capital expenditure projections, Mr. Coppola recognized that the Company spent $2,406,000 for 2024 for the combined projects.[1194]

Mr. Coppola characterized the Company's decision to fully staff the Grand Rapids center as "a 180 degree turn by the Company in less than 24 months."[1195] He also opined that the tradeoff of the new proposal, costing $30.2 million with $10.2 million in forecasted annual savings, was not advantageous to customers. He stated that the overall cost was increasing by $13 million, and he opined that the additional cost savings of $1.6 million annually was both minimal and based on unproven anticipated

[1191] 3 Tr 2161-2166.
[1192] 3 Tr 2162-2163.
[1193] 3 Tr 2488-2489.
[1194] 3 Tr 2489.
[1195] 3 Tr 2489.

efficiencies and faster customer restoration time from power outages.[1196] Mr. Coppola expressed skepticism regarding Consumers' discovery responses forecasting, especially forecasts that Consumers will save $3.1 million in costs by 2027 by increasing storm restoration by 2 hours per event, and that two centers would accomplish this better than one. Undermining Consumers' claims, he cited a $3.5 million savings forecast regarding early storm declarations and storm team activations for smaller storms that did not explain "[w]hy two fully staffed centers instead of one" would accomplish the savings.[1197]

He also cited a Consumers discovery response with a list of projected savings, found in Exhibit AG-22; Mr. Coppola calculated that this list would only result in $7.8 million in cost savings in the projected test year.[1198] He recommended that the Commission reject the proposal to have two fully staffed control/dispatch centers, recommending full disallowance of $10,746,000 for the bridge period and $15,497,000 for the projected test year. In the alternative, Mr. Coppola recommended that O&M for the projected test year be reduced by $7.8 million.[1199]

Mr. Guinn countered that both control/dispatch centers are essential for operational resilience and risk mitigation, relying on Mr. Snider's rebuttal testimony.[1200] Mr. Snider, in turn, testified regarding resilience and risk mitigation, noting multiple tornado warnings and other weather events that required control to be automatically transferred from Jackson to Grand Rapids and that required full staffing at both facilities.

[1196] 3 Tr 2389-2490.
[1197] 3 Tr 2490.
[1198] 3 Tr 2490.
[1199] 3 Tr 2491.
[1200] 3 Tr 625.

Full staffing also assisted with employee retention by avoiding forced relocations. Mr. Snider believed Mr. Coppola had oversimplified both the evolution of the current proposal and the difficulty of closing one facility and absorbing its workload into another.[1201] Nevertheless, Mr. Snider admitted that the $10.2 million in estimated savings was based on projected cost avoidance and efficiency gains, but he characterized the dual-center control/dispatch center model as a "strategic advancement informed by lessons learned and employee feedback," rather than a reversal of prior strategy.[1202]

Staff requested a lesser disallowance than Mr. Coppola, with Ms. Duell pointing out that Consumers projected 2024 spending of $4,400,000 in 2024 in Case No. U-21585 but indicated in this case that the Company had only spent $2,406,000.[1203] As a result, Staff recommended disallowance of $2,435,000 of the $4,871,000 requested by the Company for the 4 months ending April 30, 2026 and $7,748,500 of the $15,497,000 in the projected test year.[1204] This halved the amounts requested by Consumers for the Control/Dispatch Center project based on the Company having only spent roughly half of its requested amount for 2024.[1205]

Mr. Snider contended that Staff's proposed disallowances in the bridge period and test year did not take into account that previously completed engineering, design and implementation activities were all still usable in 2024 during the transition from a unified control center model to a dual location model, while the lower than predicted

---

[1201] 3 Tr 2176-2177.
[1202] 3 Tr 2177.
[1203] 6 Tr 4400-4401.
[1204] 6 Tr 4400-4401, 4406.
[1205] 6 Tr 4400-4401.

2024 spending was due to Consumers prolonging the design phase of the project to address the change. Mr. Snider maintained that the proposed bridge period and test year spending were appropriate and based on industry best practices and technology integration.[1206] Mr. Snider also noted that the prior projected spending was not approved in Case No. U-21585; as a result, Staff's comparison of projected versus actual spending was unsupported, because the Company engaged in only "prudent and targeted" spending in regulatory compliance.[1207] Mr. Guinn reiterated the Company's position that, because the control dispatch center project spending was disallowed in Case No. U-21585, the projected spending in that case was "not relevant," and Consumers was not "required to execute the projected spending" from the prior rate case.[1208]

Consumers' brief reflects its testimony, highlighting the risked loss of talent if the Grand Rapids location was to be unstaffed, the benefits to be realized through staffing two service centers, and the fact that three dispatch centers had already been merged into two, along with HVD and LVD operations groups resulting from the combination and redistributed operations for efficiency of three original operating groups.[1209] The brief further highlights the projected two-hour improvement of gray sky restoration times, and a full day's improvement in relation to catastrophic conditions, by March 2028.[1210] The brief also quotes the December 21, 2006 order in Case No. U-14561, pp. 3-4, in answer

---

[1206] 3 Tr 2178-2180.
[1207] 3 Tr 2180-2181.
[1208] 3 Tr 628.
[1209] Consumers brief, 129-131.
[1210] Consumers brief, 130-131.

to Mr. Coppola implying that avoided costs are not real savings for the proposition that avoided costs are "real savings nevertheless."[1211]

In response to the Attorney General, Consumers contends that it has adequately explained how two staffed locations will avoid costs, and that it realized $3.4 million in actual avoided costs in 2024.[1212] In response to Staff's recommended halving of the requested spending, Consumers repeats that "the Company should not be held to planned spending that was not approved," and that historical spending rates "overlook the strategic evolution of the project" during a previously unanticipated elongation of the design phase.[1213] Consumers takes the position that complex operational infrastructure does not follow linear spending patterns, and urges the Commission to allow the expenditure to support reliability, resiliency, and best practices.[1214]

The Attorney General's brief echoes Mr. Coppola's testimony, emphasizing that the Company does not adequately explain how two fully staffed centers will create incremental savings over one staffed center, and that Mr. Coppola's calculation of the cost savings from the Company's figures yields only $7.8 million in potential savings.[1215] The Attorney General asserts instead that building two redundant centers and duplicating staff is increasing capital expenditures, and repeats the recommendation to eliminate $10,746,000 for the bridge period and $15,497,000 in capital expenditures for the projected test year, or, in the alternative, to eliminate $7.8 million from O&M if the

[1211] Consumers brief, 131-132.
[1212] Consumers brief, 131-132.
[1213] Consumers brief, 133.
[1214] Consumers brief, 133-134.
[1215] Attorney General brief, 92-93.

capital expenditures are permitted to reduce O&M by the potential cost savings of the project.[1216]

Staff's brief continues to advocate for the disallowance of $2,435,500 for the bridge period, and $7,748,500 for the test year, contending that, in the prior cases where spending was disallowed, Consumers had not yet secured design and engineering services bids, and funding was premature. However, the 2024 expenditures were not disallowed until March of 2025. Staff theorizes that "the Company should have been operating under its plan to spend $4,400,000 in 2024, as it projected in U-21585. Instead, the Company only spent $2,406,000." Staff maintains that the underspending warrants a reduction to the projected bridge period and test year spending.[1217]

Consumers' reply brief responds that the Company was spending amounts authorized in Case No. U-21389 in 2024, but was not spending unauthorized funding under the projections of the most recent prior rate case, Case No. U-21585.[1218] Consumers contends that the unspent amounts based on its denied spending request should not be controlling regarding projected expenditures in this case, which the Company maintains are sound.[1219]

In the prior rate case, when only one consolidated control/dispatch center was contemplated to be finished in the third quarter of 2026, the Commission denied Control/Dispatch Center Consolidation Project funding because the project was only

---

[1216] Attorney General brief, 94.
[1217] Staff brief, 64-67.
[1218] Consumers reply, 3.
[1219] Consumers reply, 3.

entering into the design and engineering phase.[1220] The Commission indicated then that Consumers could seek recovery in a future rate case if accompanied by cost and timeline evidence.[1221] In this case, Parnall Road project construction was to start in late December 2025, and the Grand Rapids Project construction was to start in early January 2026, with long lead time materials ordered shortly before both start dates. The asset in service date for the Parnall Road project is forecasted as March 19, 2027, and the asset in service date for Grand Rapids is October 21, 2026.[1222]

At least some progress appears to have been made to justify at least some spending in relation to the Control/Dispatch Center Consolidation Project. However, irrespective of the disallowance in U-21585, the Company appears to be underspending its capital expense projections, as presented by Staff. This PFD recommends adoption of Staff's recommended disallowance of $2,435,500 for the bridge period, and $7,748,500 for the test year, to bring projected spending more in line with likely actual spending. It appears that Consumers anticipates O&M savings to be realized by 2028, and not necessarily by the end of the test year, rendering Mr. Coppola's requested O&M reduction inappropriate for the test year's timeframe.

b. Other Equipment and Emergent Repairs

Consumers initially projected $838,000 in Other Equipment spending for the bridge period and $670,000 for the test year as part of its annual budget setting process, with the category including wellness equipment, computer equipment, print equipment, real estate tools and equipment (primarily used for surveying), supply chain

[1220] March 21, 2025 order in Case No. 21585, pp. 179-182.
[1221] March 21, 2025 order in case No. 21585, p. 182.
[1222] Exhibit A-106, pp. 15-16.

tools and equipment, and facilities tools.[1223] For Staff, Mr. Hansen noted that Consumers was requesting $357,000 for historic year 2024, $838,000 for the projected 16 month bridge period ending April 30, 2026, and $2,706,000 for the projected test year.[1224] Staff recommended disallowance of $98,200 for other equipment for the test year to reduce the forecasted spending to the five-year historic average. Mr. Hansen indicated that Consumers did not provide evidence for why the Company's projection was higher than the average.[1225] Staff's recommended disallowance was uncontested by Consumers; Mr. Gast testified regarding the withdrawal of the $98,200, and this reduction is undisputed in Consumers' brief.[1226] The concession is noted in Staff's brief, as well.[1227] With the apparent agreement of the parties, this PFD recognizes the $357,000 in spending for 2024, and recommends approval of $838,000 for the 16 month bridge period ending April 30, 2026 and $2,607,800 for the test year.

Turning to Emergent Repairs, Mr. Guinn testified that Consumers is projecting capital expenditures of $1,344,000 for the bridge period, and $2,706,000 for the test year, for the emergent repairs portfolio. This includes unplanned corrective maintenance and break fix repair of assets. The Company used data on the age, condition, and maintenance history of major building system assets, along with historical spending, to forecast spending amounts.[1228]

Mr. Coppola recommended disallowance of the full $2,706,000 for emergent repairs for the projected test year because the Commission has previously rejected

---

[1223] 3 Tr 551-552.
[1224] 6 Tr 4314-4315.
[1225] 6 Tr 4315-4316.
[1226] 3 Tr 625, 629. Consumers brief, 127-128.
[1227] Staff brief, 67-68.
[1228] 3 Tr 553.

inclusion of placeholder amounts in rate base. In his view, Consumers had not identified any specific or known projects to support the spending, thus rendering the projected emergent repairs a placeholder amount.[1229] Mr. Guinn countered that emergent repairs is for unplanned corrective maintenance and asset repairs. According to Mr. Guinn, these expenses are unknowable by their nature, which is why the Company uses, and the Commission has previously accepted, a five-year average for the emergent repairs forecast.[1230] Consumers' brief echoes Mr. Guinn's testimony.[1231] The Attorney General's brief echoes Mr. Coppola's testimony and the recommended disallowance of $2,706,000, adding that "Commission orders are not purely precedential."[1232]

Mr. Hansen presented Staff's recommended disallowance of $948,800 for projected test year emergent repairs because this is the amount by which, without explanation, the Company's projection exceeded Consumers' five-year spending average.[1233] Mr. Guinn, in rebuttal, agreed to the removal of the $948,800 from the case. This resulted in a reduction of line 7 of Exhibit A-102 "from $2,705,793 to $1,756,993 for the 12 months ending April 2027."[1234] This is further supported by Consumers' brief, which agrees that the original prediction was based on a Company error calculating the five-year average.[1235]

Although the Attorney General is correct in asserting that placeholder amounts are generally disallowed, it is not reasonable to anticipate that nothing will break in the

---

[1229] 3 Tr 2491-2492.
[1230] 3 Tr 624, 626.
[1231] Consumers brief, 134-135.
[1232] Attorney General brief 94-95.
[1233] 6 Tr 4314-4316.
[1234] 3 Tr 625, 629.
[1235] Consumers brief, 134.

projected test year. Staff's recommended disallowance to reduce projected emergent repairs spending to the five-year spending average is reasonable. Without apparent opposition from Consumers, this PFD recommends allowance of $1,344,000 for the bridge period, and $1,756,993 for the test year, for the emergent repairs portfolio.

5. Fleet Services

The Company is projecting fleet services capital spending of $21.581 million for the 12 months ending December 31, 2025; $4.368 million for the 4 months ending April 30, 2026; $25.948 million for the 16 months ending April 30, 2026; and $67.947 million for the projected test year ending April 30, 2027.[1236] For the historical year ending December 31, 2024, Consumers incurred Fleet Services capital expenditures in the amount of $16.628 million.[1237] Mr. Guinn testified that Consumers makes direct capital investments in its fleet as set forth in Exhibit A-12, Schedule B-5.6, page 4.[1238] The capital costs are spread amongst the cost categories in the exhibit, and across Fleet Services' three departments of Fleet Maintenance Operations, Fleet Acquisition, and Shared Services Governance Performance and Technology.[1239] Mr. Guinn testified that Consumers had not included any contingency costs in these projections.[1240] Instead, the spending is projected based on historical spending levels adjusted for inflation.[1241]

As reflected in the Exhibit, Fleet Services capital spending is broken down into: (1) Fleet Vehicle Capital Replacement; (2) Fleet Vehicle Electrification; (3) Fleet

---

[1236] 3 Tr 613.
[1237] 3 Tr 613.
[1238] 3 Tr 581.
[1239] 3 Tr 579, 613-615.
[1240] 3 Tr 613.
[1241] 3 Tr 615.

Expansion; (4) Fleet Business Partner Funded, and (5) Fleet Tools-Garage.[1242] Fleet Business Partner Funded and Fleet Tools-Garage capital spending do not appear to be contested, and this PFD recommends the allowance of that requested spending without apparent objection. Fleet Capital Replacement, Fleet Capital Expansion, and Fleet Electrification, are discussed below.

a. Vehicle Replacement Plan

Mr. Guinn testified that, for Fleet Capital Replacement, Consumers is projecting spending of $19.882 million for the 2025 bridge year; $4.282 million for the 4 months ending April 30, 2026; $24.164 million for the 16 months ending April 30, 2026; and $20.778 million for the test year.[1243] Mr. Guinn explained Exhibit A-104, and the expenditures included in both the Fleet Vehicle Capital Replacement Plan and Expansion HVD capital spending, noting that the exhibit lists the specific units that the Company plans to purchase for 2024 through 2027.[1244] He indicated that the Fleet Vehicle Capital Replacement Plan and Fleet Vehicle Electrification capital spending include the offset cost of ten EV pickup trucks, with two of these for electric use and "eight units for common use, as well as 12 Altec JEMS ePTO systems in spec 64 bucket trucks."[1245]

Mr. Guinn presented the Company's overall fleet structure, including approximately 2,800 light duty vehicles, 1,500 medium and heavy-duty trucks, approximately 1,400 units of various equipment, and approximately 1,900 trailers, for a

[1242] 3 Tr 613.
[1243] 3 Tr 615.
[1244] 3 Tr 614, 616.
[1245] 3 Tr 614. The term "ePTO" is Power Take Off systems.

total 7,207 owned, leased, and rented units across 36 locations.[1246] According to Mr. Guinn, the fleet is categorized into several specifications (specs) relating to the type, model, and description of vehicles, with each spec related to a defined intended use, acquisition cost, operating cost, and expected life in years and mileage.[1247] Mr. Guinn discussed the division of the fleet into the Company's electric and natural gas businesses, with fleet requirements varying by work to be performed, location, crew counts, and region.[1248]

Mr. Guinn further outlined the fleet replacement planning process and its development, detailing the blended factor calculation, the fleet cost tool, and the crewing model tool used in the process.[1249] He opined generally regarding the benefits of the planning process, including reducing overall costs through more effective use of individual vehicles, and that replacing vehicles can enhance safety by adding new features, such as backup sensors and rear-view cameras, reducing stopping distance, and improving visibility with LED headlights.[1250] Mr. Guinn also discussed the fleet utilization tool incorporated into the fleet replacement process.[1251]

In discussing the benefits of the process, Mr. Guinn took the position that the utilization rate data from the fleet utilization tool benefited customers by demonstrating vehicles out of use for repair versus vehicles that receive little use, allowing for redundancies to be reduced through attrition or reallocation.[1252] He elaborated that

---

[1246] 3 Tr 580, 596.
[1247] 3 Tr 580.
[1248] 3 Tr 581, 596.
[1249] 3 Tr 484-488, 583-598, 616-617.
[1250] 3 Tr 596-600.
[1251] 3 Tr 594-596.
[1252] 3 Tr 596.

"[p]eak utilization of all vehicles is a balance between fully utilizing purchased assets and having the right asset in place and ready when needed at a moment's notice when responding to outages, new business, or construction situations."[1253] With the exception of specialized equipment, information on underused units drives decisions on future investments, with a focus on "right sizing" the fleet; Mr. Guinn noted that the Company has reduced the number of units by approximately 450 since mid-2022.[1254] The incorporation of use data allows Consumers to maintain the fleet to manufacturers' specifications, while addressing periodic wear and tear, and planning for appropriate replacement or elimination.[1255]

Mr. Coppola reviewed the Company's historical purchase information by vehicle class and used this information to calculate average per vehicle cost. He averaged vehicle purchase cost from 2022 through 2024, applied inflation factors of 2.9% and 2.4% to reflect cumulative inflation through the end of the projected test year, and then multiplied this by the 89 forecasted vehicle purchases.[1256] This gave him a total fleet replacement purchase cost of $16,407,000. From this, Mr. Coppola recommended a reduction of $4,371,000 to fleet replacement purchases, representing the difference between his total cost calculation and the Company's $20,778,000 forecasted capital expenditures.[1257]

[1253] 3 Tr 598.
[1254] 3 Tr 598-609.
[1255] 3 Tr 598-600.
[1256] 3 Tr 2492-2494.
[1257] 3 Tr 2494, citing Exhibit AG-25.

Mr. Coppola also took the position that many existing fleet vehicles are underused and could be put to more efficient uses to reduce new fleet purchases.[1258] With approximately 1,050 vehicles used between 5% and 20% of the time, and the remaining 1,216 vehicles used between 20% and 50% of the time, Mr. Coppola recommended that the Commission require Consumers to "present a thorough plan in the next rate case that addresses the utilization rate of vehicles and field equipment and the impact on reduced vehicle purchases in future years."[1259]

Mr. Guinn responded that Mr. Coppola's proposed reduction was unwarranted.[1260] Instead of Mr. Coppola's "insufficient" three-year average, the Company starts with the $17,943,000 test year amount permitted in Consumers' Vehicle Capital Replacement Plan from Case No. U-20963, then adds an inflation factor to each prior calendar year's amount, a method that the Commission accepted in that same case.[1261] However, while not fully agreeing to Mr. Coppola's proposal, Mr. Guinn agreed that Consumers would "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."[1262]

The Attorney General's brief emphasizes that, in comparison to the $25.9 million in fleet services capital expenditures projected for the bridge period, and particularly in comparison to the Company's proposed $67.9 million in transportation fleet spending for the projected test year, Consumers had only $16.6 million in capital expenditures for

---

[1258] 3 Tr 2493, 2495-2496.
[1259] 3 Tr 2495-2496.
[1260] 3 Tr 624.
[1261] 3 Tr 626-627.
[1262] 3 Tr 627.

2024.[1263] The Attorney General contends that Consumers did not disclose any vehicle price data for the projected test year, so the source and validity of the 2026 and 2027 prices used were unverifiable and higher than normal inflation projections. As a result, it follows that Mr. Coppola's use of the 2022 through 2024 average price was appropriate, and appropriately multiplied by the 89 forecasted vehicle purchases to yield a total forecasted purchase price of $16,407,000; this is $4,371,000 lower than the $20,778,000 forecasted by Consumers, and the $4,371,000 should thus be disallowed.[1264] The Attorney General concludes by repeating Mr. Coppola's points regarding the lack of use of Consumers' existing fleet, and advocating that the Commission require Consumers to provide a thorough vehicle and field equipment use plan that includes the impact on reduced vehicle purchases in future years through increased use of existing vehicles.[1265]

In contrast, Consumers' brief asserts that the Company is keeping Fleet Vehicle Capital Replacement Plan spending at historic spending levels adjusted for inflation, and that the "lifecycle replacement spending" has been approved by the Commission "in every rate case since Case No. U-20963."[1266] The Company took the test year amount of $17,943,000 "allowed" by the Commission in Case No. U-20963, then calculated successive calendar year amounts by adding an inflation factor to the prior year's amount.[1267] Consumers' characterizes the Attorney General's calculation method as

[1263] Attorney General brief, 95-96.
[1264] Attorney General brief, 96-97.
[1265] Attorney General brief, 97-99.
[1266] Consumers brief, 136-137.
[1267] Consumers brief, 136-137.

unsupported and insufficient to maintain the replacement plan, ultimately resulting in increased maintenance expenses.[1268]

This PFD declines to adopt the Attorney General's reductions in fleet replacement spending; the fleet replacement price projections in the Company's Exhibit A-104 are more aligned with actual vehicle prices than Mr. Coppola's recalculation in Exhibit AG-25. Furthermore, requiring Consumers to demonstrate more efficient vehicle usage, and requiring this to demonstrate the elimination of replacement vehicle purchasing, is unsupported. Many of Consumers' fleet vehicles are necessary but highly specialized.[1269] Consumers has already presented testimony regarding elimination of 450 fleet vehicles since mid-2022.

Nevertheless, the Attorney General's point is well-taken; this PFD recommends that Consumers be directed to include more detail regarding existing vehicle usage by spec in its next electric rate case filing. It appears that Consumers is open to providing a plan addressing vehicle and field equipment use in its next rate case,[1270] and this would reduce discovery and provide useful information regarding the reasonableness of vehicle purchasing going forward. The same is true of the additional information regarding actual units to be purchased, and purchase prices, and this PFD encourages Consumers to provide greater detail in future filings, to the extent possible. However, this PFD recognizes that what automakers choose to produce can change and that this is outside of the Company's control. Thus, while this PFD encourages Consumers to

---

[1268] Consumers brief, 136.
[1269] For example, many of the vehicles appearing on the first page of Exhibit AG-26 with 0% use are trenchers and excavators, and, in the list of the first 151 vehicles with less than .5% use, there are three digger derricks.
[1270] 3 Tr 627.

provide greater detail regarding actual vehicles to be purchased in the next rate case filing, it does not make a recommendation for a specific Commission directive on this issue.

b. Vehicle Expansion Plan

Mr. Guinn testified that the Company intends to make investments of $648,000 in calendar year 2025; $15,170,000 in calendar year 2026; and $46,070,000 in the test year to support Electric Operations workforce expansion. This will include pick-up trucks with specific upfits to perform work related to HVD operations.[1271] Mr. Guinn opined that members of the workforce that construct and maintain electric distribution infrastructure could be stranded without vehicles and necessary equipment if the proposed expansion expenditures are not approved.[1272]

Mr. Coppola testified that, of the 229 fleet expansion vehicles to be purchased in the projected test year, 71 are for electric undergrounding work and 158 vehicles are for other LVD programs.[1273] Because Mr. Coppola is recommending disallowance of the undergrounding program, and he proposed significant reductions to LVD capital spending, he removed the 71 vehicles in relation to the undergrounding program, and he cut the LVD-related vehicles by half, when calculating fleet expansion cost.[1274] He generally used the same method for fleet expansion that he used for determining the unit cost of vehicles in relation to fleet replacements, multiplying the reduced number of expansion units by average unit cost, plus inflation, for a forecasted fleet expansion cost of $18,139,000. This is $27,931,000 lower than the Company's $46,070,000 forecast,

[1271] 3 Tr 619, citing Exhibit A-104.
[1272] 3 Tr 619.
[1273] 3 Tr 2493.
[1274] 3 Tr 2493.

resulting in his recommended $27,931,000 reduction.[1275] Adding his calculated fleet maintenance and fleet expansion reductions together, Mr. Coppola recommended a $33,142,000 reduction in test year vehicle purchase capital expenditures.[1276]

Mr. Guinn opposed Mr. Coppola's proposed reduction to the vehicle capital expansion plan capital expenditure, relying on Mr. Kelly's testimony in support of the undergrounding program and other LVD capital program and projects. Mr. Guinn repeated his initial testimony that failing to permit the expansion plan would put the Company at "acute risk of some members of its frontline workforce being without vehicles and equipment necessary to perform reliability work."[1277]

The Attorney General's brief defends Mr. Coppola's removal of the 71 undergrounding vehicles, and 79 of the other LVD program vehicles, from the 229 new planned vehicle purchases for the projected test year, to "avoid having excessive vehicles on hand for work that may not materialize," while the Company already has many vehicles that could be put to better use.[1278] The Attorney General otherwise supports Mr. Coppola's calculation and recommended disallowance of $27,931,000 for fleet expansion in the projected test year.

Consumers' brief clarifies that the "projected expenditures are used to purchase pickup trucks with specific upfits for Electric Operations substations to perform work related to HVD operations," as set forth in Exhibit A-104, and supported by Mr. Kelly's testimony.[1279] The Company takes the position that its OHUG and LVD capital

---

[1275] 3 Tr 2493-2495.
[1276] 3 Tr 2495.
[1277] 3 Tr 627.
[1278] Attorney General brief, 96-97.
[1279] Consumers brief, 137.

programs are fully supported. Failure to approve the expansion amounts will strand members of Consumers' workforce without the necessary equipment and vehicles; Consumers therefore requests approval of its vehicle expansion plan and associated costs.[1280]

This PFD recommends adoption of the Attorney General's recommended disallowance of $27,931,000 for fleet expansion in the projected test year. Staff does not comment on fleet expansion, but Staff recommends disallowance of some of the Company's undergrounding spending based on underspending in 2025.[1281] Although it seems unlikely that the Commission will reject the entirety of the undergrounding and LVD work to which the Attorney General objects, and on which the Attorney General's proposed fleet expansion reduction largely rests, Staff's underspending concerns call into question whether the Company will be able to scale up the work as proposed and actually need an additional 229 vehicles.[1282] This seems unlikely. The remaining recommended allowed $39,757,00 in spending seems more likely to be realized in the test year.

c. Fleet Electrification

The Company is proposing to spend $840,000 in the test year on fleet vehicle electrification, including internal combustion engine (ICE) to electric vehicle (EV) replacements, and $600,000 to install JEMS idle mitigation units on 12 bucket trucks.[1283] Mr. Guinn testified that the replacement of ICE vehicles with EVs would follow the same replacement process as other types of vehicles, but the Company adds

[1280] Consumers brief, 137.
[1281] See *e.g.* Staff brief, 26, 110.
[1282] Exhibit A-104.
[1283] 3 Tr 617, citing Exhibit A-104.

the fleet electrification filter to determine if a unit targeted for replacement would be a good candidate for replacement with an EV. He then outlined the electrification filter,[1284] and stated that Consumers is planning to increase the number of EVs in its fleet to reduce fuel, maintenance, and operating costs, as well as tailpipe emissions.[1285]

According to Mr. Guinn, the Company's fleet has approximately 302 EVs, approximately 5% of the fleet, with EV defined by the Edison Electric Institutes to include all vehicles with a plug, including battery EV, plug-in hybrids, and anti-idle job site systems like Power Take Off systems (ePTO) units.[1286] Consumers has set a goal of 30% electrification of its approximately 5,700 powered vehicle internal fleet by 2030, including light, medium, and heavy-duty vehicles, equipment and powered trailers, and electrifying all class 1 and 2 vehicles after 2030.[1287] This would entail replacement of approximately 1,700 internal combustion engine (ICE) units with fully or partially EV powered units, focusing on sedans and pickup trucks, with additions of medium and heavy-duty vehicles as battery technology develops and more replacement analog EVs enter the market.[1288]

Mr. Guinn highlighted the Company's addition of one of the first available electric bucket trucks in late 2024 to be deployed in Grand Rapids, along with the addition of 20 all-electric pick-up trucks.[1289] The price difference between the chassis on each type of pick-up truck is "approximately $40,000, totaling approximately $240,000 for 10 EV pick-

[1284] 3 Tr 602-604.
[1285] 3Tr 601.
[1286] 3 Tr 601.
[1287] 3 Tr 601-602.
[1288] 3 Tr 602.
[1289] 3 Tr 602.

up trucks.[1290] Consumers seeks to add the purchase price difference between a standard ICE chassis and the electrification cost of the replacement unit as the fleet electrification cost, with Mr. Guinn touting the anticipated benefits of EVs.[1291]

Mr. Guinn testified that the Five-Year Purchase Plan identifies 120 to 130 opportunities for "suitable 1:1 replacement of an ICE with an EV based on replacing units that have reached the end of their life," primarily light duty pick-up trucks and plug-in battery idle mitigation units on bucket trucks.[1292] The Company has identified about 22 light duty vehicles in 2026, 20 opportunities in 2027, 23 in 2028, 22 in 2029, and 25 to 30 units in 2030, for EV replacement.[1293] Mr. Guinn stated that, "[w]ith limited opportunities to make ICE to EV replacements through 2027," Consumers will need to invest more than the currently approved capital replacement funding, approximately 450 EVs more per year than the current purchase plan identifies for 2028 through 2030, to reach the Company's goal of 1,700 EVs.[1294] The Company is planning to replace 10 ICE pick-up trucks with 10 plug-in EV pick-up trucks in the test year.[1295]

Mr. Guinn stated that, per Case No. U-20963, Consumers partnered with the non-profit CALSTART, fleet electrification experts selected via a competitive RFP. CALSTART analyzed the Company's light, medium, and heavy-duty fleet vehicles by location and daily miles driven between August 22 and October 23, which provided approximate load demand by location.[1296] This EV location determination assists in

---

[1290] 3 Tr 617-618.
[1291] 3 Tr 604-606, 611-612, 617-618.
[1292] 3 Tr 609.
[1293] 3 Tr 609.
[1294] 3 Tr 609.
[1295] 3 Tr 611.
[1296] 3 Tr 606-607.

estimating potential carbon emission avoidance and cost benefit analysis.[1297] CALSTART also concluded that Consumers could lower its fuel and maintenance costs by approximately 70%, excluding vehicle purchase price, over the lifetime of the electrified vehicles, potentially reducing tailpipe emissions by roughly 90,000 metric tons.[1298] Mr. Guinn continued that, in addition to CALSTART's assessments, the analysis also used the Company's own fleet-generated data to compile a list of recommended vehicle electrification locations, the estimated load demand for those locations, and the charging information to support them.[1299]

Mr. Guinn indicated that the assessments provide location-based electric load demand estimates for replacement light duty EVs, along with electricity as fuel cost estimates based on current mileage driven by ICE vehicles.[1300] From this, Mr. Guinn further indicated that the Company could determine the necessary infrastructure electrical upgrades and the installation of Electric Vehicle Supply Equipment (EVSE), commonly referred to as chargers, at affected service centers.[1301] The number of EVs, thus load demands and the chargers and other electric infrastructure needed, will vary by location. To this end, Mr. Guinn referred again to the CALSTART assessment as the basis for Consumers' demand load forecast for daily EV charging.[1302] Use of the assessment's information regarding standard driving miles per day and vehicle uses,

---

[1297] 3 Tr 607.
[1298] 3 Tr 607.
[1299] 3 Tr 607.
[1300] 3 Tr 608.
[1301] 3 Tr 608-609.
[1302] 3 Tr 609.

"partner[ing] with operations," informs Consumers whether an EV will meet the work processes requirements of a particular location.[1303]

Mr. Guinn indicated that EVs generally have higher purchase costs than comparable ICE vehicles. He added that, when seeking a suitable EV replacement, Consumers looks for the closest EV equivalent to the ICE being considered for replacement while considering the operational stability of the manufacturer to ensure support over the EV's lifetime.[1304] Mr. Guinn indicated the Company's preference for original equipment manufacturer (OEM) vehicles from Michigan-based companies, like Ford and General Motors, to limit the potential risks associated with startup company products.[1305] This, along with changing EV market conditions, and more than two-year ordering times, limits the size of the EV market and the availability of fleet-suitable EVs, with most EVs failing to meet the criteria for cost and features best suited for Company use.[1306] Pickup trucks and sedans generally have the most suitable transportation and operational support corollaries.[1307] According to Mr. Guinn, the limited availability of EVs may prevent the Company from being able to purchase more than the current 20 to 30 units per year, thereby preventing Consumers from reaching its 30% fleet electrification goal by 2030.[1308]

Mr. Jester questioned Consumers' 30% fleet electrification target and how it was conceived.[1309] He contended that the CALSTART review was structured to meet the

---

[1303] 3 Tr 611.
[1304] 3 Tr 608.
[1305] 3 Tr 610.
[1306] 3 Tr 610.
[1307] 3 Tr 608.
[1308] 3 Tr 609-610.
[1309] 6 Tr 3997-3998.

30% electrification goal, and was not intended to identify all vehicles that could be reasonably replaced with EVs under current market conditions.[1310] To Mr. Jester, because Consumers owns the means of electrification, and because there are electric analogs for the light-duty vehicles that comprise the bulk of the Company's fleet, the Company should target all light-duty vehicle replacements to be completed by 2030, exceeding Consumers' current 30% electrification target.[1311]

Mr. Guinn responded that fulfilling all light duty vehicle replacements with electric vehicles by 2030 would require departure from the Commission-approved Fleet Capital Replacement Plan Filter and the Blended Factor methods used to prioritize fleet replacement purchases.[1312] It was also unclear if replacement of all light duty vehicles could be completed at historical spending amounts.[1313] Finally, Mr. Guinn expressed concern that replacing all light duty vehicles with EVs would take priority over replacing heavy duty vehicles and equipment "more directly relevant to performing electric system reliability work such as bucket trucks."[1314] Mr. Guinn was also cross-examined, with the result being that Consumers expressed a willingness to provide an assessment whether substitution of EVs for all currently-scheduled light-duty replacements by 2030 would require departing from vehicle capital replacement historical spending levels.[1315]

Consumers brief similarly indicates that the Company "agrees to provide an assessment of fulfilling just the light-duty vehicles that are due for replacement with EVs

---

[1310] 6 Tr 3997-3998.
[1311] 6 Tr 3997-3999.
[1312] 3 Tr 628.
[1313] 3 Tr 628.
[1314] 3 Tr 628-629.
[1315] 3 Tr 632-633.

between now and 2030."[1316] The brief also highlights that the Fleet Electrification spending of $840,000 for the 12 months ending April 30, 2027 is intended to "fund the difference between the purchase price of a standard pickup truck and its EV equivalent."[1317]

MNSC's brief reflects the points made in Mr. Jester's testimony, further decrying that Consumers "is 'reevaluating' and likely stepping back from its current 30 percent target, even though 'commercially available models exist for most of the vehicle and vehicle types in the Company's fleet.'"[1318] MNSC contends that its recommendation to electrify all light-duty vehicle replacements by 2030 aligns with normal replacement cycles, ensuring that Consumers leads by example on vehicle electrification, and benefiting customers through lower EV maintenance and fueling costs.[1319] MNSC rejects Mr. Guinn's opposition to Mr. Jester's recommendation, characterizing it as based on the assumption that what was being proposed was replacement of the entire 900-vehicle light duty fleet with EVs for 2030, which was later invalidated by Mr. Guinn's concession that the recommendation is for EVs being purchased for all scheduled light duty vehicle replacements by 2030.[1320] MNSC repeats its recommendation that the Commission direct Consumers to fulfill all light duty vehicle replacements with electric models by 2030.[1321]

This PFD recommends that Consumers' current fleet electrification spending proposal be approved. Further, as already noted, Consumers agreed to provide an

[1316] Consumers brief, 138.
[1317] Consumers brief, 138.
[1318] MNSC brief, 20-21.
[1319] MNSC brief, 21.
[1320] MNSC brief, 21-22.
[1321] MNSC brief, 22.

assessment of the viability of using EVs for all, already-scheduled light-duty vehicle replacements between now and 2030.[1322] Given recent changes in the EV market, as reflected in the general media, such an assessment seems prudent. Without apparent opposition from the Company, this PFD recommends the preparation and filing of such an assessment in the next rate case. However, without such an assessment in evidence, this PFD declines to recommend mandatory adoption of a higher EV replacement rate than is already reflected for the projected test year.

6. IT and Security Capital Expenditures

a. Overview

Ms. Baker testified that technology is an integral part of all aspects of the Company's electric strategy from generation all the way to the customer.[1323] She stated that the Company needs to invest in new technology to realize its plan of transforming to clean energy; to achieve a more reliable and resilient modern electric grid; and to establish data analysis techniques to understand, communicate, and engage with the Company's customers.[1324] She stated that the IT Department faces a challenge when it comes to the integration and implementation of emerging technologies, data, and analytics needed to achieve the Company's goals described in the Integrated Resource Plan (IRP) and Electric Distribution Infrastructure Investment Plan (EDIIP).[1325] According to Ms. Baker, security is another challenge that presents a significant risk for utilities.[1326] She explained that cyber threats are increasing in their impact and level of

[1322] Consumers brief, 138.
[1323] 3 Tr 647.
[1324] 3 Tr 647-648.
[1325] 3 Tr 649.
[1326] 3 Tr 649.

sophistication, requiring timely patching and upgrades and replacements to IT software and systems, and that physical threats (including theft, equipment damage, vandalism, and intentional gunfire aimed at disrupting the grid) are evolving and present challenges in maintaining a reliable and safe electricity supply.[1327]

Ms. Baker testified that Consumers allocated $44,023,000 for IT-related capital expenditures in the 2024 historical year, while the Company projects it will invest $80,310,000 during the bridge period and $77,719,000 in the test year.[1328] She provided an overview of various IT projects, which are more fully described in Exhibits A-20 and A-21.[1329] She also testified that the Company's total IT capital projections reflect a 20% reduction for those projects that have projected costs based on a Rough Order of Magnitude (ROM) estimate, and she stated that due to previous disallowances, IT estimates do not include contingency.[1330]

Staff and the Attorney General proposed disallowances to various IT programs. In rebuttal, Consumers agreed to withdraw $435,000 of capital expenditures related to the ARP-Collaboration project[1331] and $88,000 related to the Service Restoration Artificial Intelligence project,[1332] resolving those issues. The remaining contested adjustments are discussed below.

[1327] 3 Tr 649-655.
[1328] 3 Tr 676-677; Exhibit A-12, Schedule B-5.1.
[1329] See 3 Tr 678-684.
[1330] 3 Tr 687-688.
[1331] Staff brief, 47-48; Consumers brief, 143, Appendix B3; Staff reply, Appendix E.
[1332] Staff brief, 63-64; Consumers brief, 163, Appendix B3.

b. IT Adjustments

i. ARP FDAM

Ms. Baker testified that the projects included in the Asset Refresh Program (ARP) replace technology assets in line with industry and Company life-cycle expectations.[1333] She sponsored Exhibit A-22, which shows the projected and actual capital expenditures of each ARP.[1334] Ms. Baker explained that the ARP-Field Device Asset Management (FDAM) project will replace field devices according to a four-year refresh cycle that is based on industry standards, hardware failures, security patches, and software compatibility.[1335] The Company originally projected that the project will require $3,985,410 of capital expenditures in the bridge period and $4,850,461 in the test year.[1336]

Staff Disallowance

Staff witness Zichi recommended a full disallowance of all new device purchases[1337] for 2026 and 2027 included in the ARP-FDAM project, totaling $228,567 in the bridge period and $658,700 in the test year.[1338] She testified that through audit, the Company stated that the projection for new purchases has changed in this case due to the uncertainty of knowing the exact number of new devices needed each year, and the Company now reviews actual historical costs over the past four years to ensure its

[1333] 3 Tr 692.
[1334] 3 Tr 693.
[1335] 3 Tr 702.
[1336] 3 Tr 702; Consumers brief, 144-145.
[1337] Ms. Baker explained that the ARP-FDAM project has two categories, replacements and new purchases, both of which include field devices. She described the two categories at 3 Tr 702-703.
[1338] 6 Tr 4345.

projection is reasonable and prudent.[1339] Ms. Zichi stated that Staff finds this new method problematic because the Company did not explicitly state that the average of all four years of historical data is used to determine the total projected costs of new device purchases; rather, the Company stated that projected costs were validated using historical costs.[1340] Ms. Zichi further testified that in response to a follow-up audit question asking the Company to share the calculation used to produce its projection, the Company stated that it did not use a calculation to project the cost for new device purchases and it referred Staff to its previous audit response and reiterated that the projected costs were *validated* using actual historical costs.[1341]

Ms. Zichi added that Staff understands the importance of new device purchases for this project and believes the Company will spend money in this area.[1342] But she opined that the Company failed to provide supporting information showing how the projected costs were derived, and without a clear explanation, the costs remain baseless.[1343] She stated that if the Company has chosen a new way of predicting new device purchases, it should have a method or calculation to support it.[1344]

In rebuttal, Ms. Baker testified that the Company provided Staff with the information and the method for projecting the new field device purchase costs based on the historical spend, including the historical actuals that were used to validate the reasonableness of the projection.[1345] Ms. Baker further testified the Company agreed

---

[1339] 6 Tr 4346, citing Exhibit S-14.1, pp. 5-6.
[1340] 6 Tr 4346.
[1341] 6 Tr 4347, citing Exhibit S-14.1, p. 15.
[1342] 6 Tr 4347.
[1343] 6 Tr 4347.
[1344] 6 Tr 4347.
[1345] 3 Tr 763, citing Exhibit S-14.1, p. 5.

that using a four-year historical average 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.[1346] She sponsored Exhibit A-183, which contains the four years of historical data for the years 2021-2024 and total Company and electric allocation four-year historical average calculations for the costs associated with new purchases of field devices.[1347] Ms. Baker proposed that based on the four-year historical average of $611,611, the Company's projected costs should be reduced by $24,696 for the bridge period and $74,089 for the test year.[1348]

In its initial brief, Consumers argues that its adjusted projection using historical data is supported by the Commission's order in the Company's latest gas rate case (Case No. U-21806), where the Commission said it would have liked to see more specific projections but agreed there was a need for field devices and approved the Company's projected costs as reasonable and prudent.[1349] The Company states that after Ms. Baker's revisions to the projected ARP-FDAM costs, it now forecasts its electric capital expenditures for the project will be $3,960,714 in the bridge period and $4,776,372 in the test year.[1350] It adds that, as Staff is not claiming that new field devices purchased through the ARP-FDAM project are unnecessary, and as the Company has agreed to the approach that Staff appears to prefer, the Commission should reject Staff's proposed total disallowance.[1351]

[1346] 3 Tr 765.
[1347] 3 Tr 765.
[1348] 3 Tr 766.
[1349] Consumers brief, 144.
[1350] Consumers brief, 145, Appendix B3.
[1351] Consumers brief, 145.

In its initial brief, Staff rejects Consumers' concession and continues to support its proposed full disallowance.[1352] Staff argues that the Company failed to provide additional information to support why using a four-year average is a reasonable and prudent projection method.[1353] It states that after reviewing the Company's rebuttal, Staff sent the Company a discovery request seeking new employee data.[1354] According to Staff, the information provided did not supply Staff with enough information to compare historical and projected new device purchases to historical and projected hires in order to validate the use of the four-year historical average for projecting new device purchases.[1355] Staff further asserts that the number of new hires needing new field device has not been demonstrated to follow the trend of historical averages.[1356] It adds that the Company previously based costs for new purchases off of anticipated People and Culture hiring estimates, which Staff found was a much more reasonable method of projecting costs.[1357]

In its reply brief, Consumers responds to Staff's claim that it was not provided enough information to compare historical and projected new device purchases to historical and projected hires.[1358] The Company states that it provided Staff with extensive information, including the specific devices being replaced; the historical costs

[1352] Staff brief, 48.
[1353] Staff brief, 52.
[1354] Staff brief, 52-53.
[1355] Staff brief, 54.
[1356] Staff brief, 55.
[1357] Staff brief, 55.
[1358] Consumers reply, 3.

needed to calculate the four-year average; and by answering Staff's questions about the projects, including its questions about new hires.[1359]

In its reply, Staff stresses that the four-year average used by the Company to project the cost of new device purchases is not Staff's preferred method.[1360]

This PFD declines to adopt the disallowance recommended by Staff. While Staff's initial concern with the underlying basis of the Company's projection was understandable, the Company has since clarified that its proposed forecast of new device purchases is based on the four-year historical average. This PFD finds that the Company has provided sufficient evidence to support its projected costs based on historical spending and recommends that the Commission accept the Company's reduction of $24,696 in the bridge period and $74,089 in the test year. This recommendation is consistent with the Commission's decision in Consumers' recent gas rate case, Case No. U-21806, where the Commission approved the Company's projected capital expenditures for new device purchases in the ARP-FDAM program based on historical spending.[1361]

Attorney General Disallowance

Mr. Coppola testified that the Company's projected test-year expenditures for ARP-FDAM is approximately double the amount allocated to the electric business in 2024 and 2025.[1362] When asked in discovery to explain the large increase in expenditures, the Company responded that the number of devices is refreshed on a

[1359] Consumers reply, 3-4, citing Exhibit A-22, p. 5; Exhibit A-183; Exhibit S-14.1, pp. 5-6; Exhibit S-21.
[1360] Staff reply, 5.
[1361] See September 30, 2025 order in Case No. U-21806, pp. 119-122.
[1362] 3 Tr 2503.

four-year cycle.[1363] Mr. Coppola reasoned that for the next refresh cycle to fall in 2026 or 2027, the previous cycle was in either 2022 or 2023.[1364] But he stated that the electric business was only allocated $1,678,000 of expenditures in 2022 and $2,224,000 in 2023, less than half the amount that the Company has included in the test year.[1365] Mr. Coppola concluded that the Company's reasoning for the increased capital expenditures does not stand up to scrutiny and is not credible.[1366]

Mr. Coppola developed a forecast for the bridge period by using the average capital spending from the three most recent historical years (2022-2024) of $2,218,000, prorating it to 16 months and applying an inflation factor of 2.9%, which results in forecasted capital expenditures of $2,957,000.[1367] Mr. Coppola recommended a disallowance of $1,039,000 in the bridge period, the difference between his forecasted amount and the Company's forecast of $3,996,000.[1368] Next, Mr. Coppola adjusted the annualized bridge-period amount of $2,282,000 by a 2.4% inflation rate to arrive at a forecasted capital expenditures amount of $2,337,000 for the test year.[1369] He therefore recommended a disallowance of $2,513,000 in the test year, the difference between his forecast and the Company's forecast of $4,850,000.[1370]

In rebuttal, Ms. Baker testified that Mr. Coppola's method does not consider that the cost projected for each year of 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

---

[1363] 3 Tr 2503.
[1364] 3 Tr 2503.
[1365] 3 Tr 2503.
[1366] 3 Tr 2503.
[1367] 3 Tr 2504.
[1368] 3 Tr 2504.
[1369] 3 Tr 2504.
[1370] 3 Tr 2504.

replaced in the four-year refresh cycle.[1371] She stated that Mr. Coppola's analysis failed to consider new field devices that were purchased as part of the ARP-WAM project in 2021, 2022, and 2023, and 425 new field devices that were purchased in 2022 for training and the Compression Digital Mobility project, which are planned to be refreshed as part of the ARP-FDAM project in 2026.[1372] Ms. Baker aggregated this data in Exhibit A-185, providing a description of the units, the number of units for the specified year, the average unit costs, actual capital expenditures, and total actual electric allocation.[1373] Ms. Baker also testified that a 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.[1374]

Ms. Baker further testified that Mr. Coppola erred in his calculation of the forecasted capital expenditures of $2,957,000, and she showed that Mr. Coppola's method actually produces a forecast of $3,043,000; therefore, his proposed bridge-period adjustment should be $953,000 rather than $1,039,000.[1375] She added that Mr. Coppola's proposed disallowance overlaps with that of Staff witness Zichi's, and they would need to be reconciled if adopted by the Commission.[1376]

In her initial brief, the Attorney General agrees with Ms. Baker's correction to Mr. Coppola's forecasted capital expenditures and requests that the Commission disallow

---

[1371] 3 Tr 800.
[1372] 3 Tr 800-801.
[1373] 3 Tr 800-801.
[1374] 3 Tr 802.
[1375] 3 Tr 802.
[1376] 3 Tr 803.

$953,000 for the bridge period, in addition to the previously recommended disallowance of $2,513,000 for the test year.[1377]

This PFD finds the Company has shown that Mr. Coppola's method of comparing historical spending to the spending presented in this case is not appropriate because it fails to account for field devices that were previously purchased as part of other projects but will be refreshed through the ARP-FDAM project in 2026. As a result, this PFD declines to adopt the Attorney General's disallowance and finds there is no basis to reduce the Company's revised capital expenditures for the ARP-FDAM project of $3,960,714 in the bridge period and $4,776,372 in the test year.

ii. ARP-WAM

Ms. Baker testified that the ARP-Workstation Asset Management (WAM) project will replace and install new desktops, laptops, and tablets on a four-year refresh cycle that is based on industry standards, hardware failures, security patches and software compatibility, while monitors will be replaced every eight years based on historical failure rates.[1378] The Company forecasted this project will require $7,358,617 of capital expenditures in the bridge period and $4,395,889 in the test year.[1379]

Staff witness Zichi recommended a full disallowance of all new device purchases[1380] for 2026 and 2027 in the ARP-WAM project, totaling $228,567 for the bridge period and $658,700 for the test year.[1381] Her rationale is the same as for the ARP-FDAM project discussed above. In short, Ms. Zichi found Consumers' projection of

---

[1377] Attorney General brief, 101.
[1378] 3 Tr 707.
[1379] 3 Tr 707; Consumers brief, 147.
[1380] Ms. Baker explained that the ARP-WAM project has two categories, replacements and new purchases, both of which include PC devices and monitors. She described the two categories at 3 Tr 709.
[1381] 6 Tr 4348.

new purchases problematic because the Company did not explicitly state that the projection is based on historical actuals, just that it is validated by it.[1382] Ms. Zichi added that Staff understands the importance of new device purchases for this project and believes the Company will spend money in this area.[1383] But she opined that the Company failed to provide supporting information showing how the projected costs were derived, and without a clear explanation, the costs remain baseless.[1384] She stated that if the Company has chosen a new way of predicting new device purchases, it should have a method or calculation to support it.[1385]

Ms. Baker's response is essentially the same as her response to Ms. Zichi's ARP-FDAM proposal (see above), although she adjusted the costs used to determine the four-year average.[1386] Ms. Baker explained that the actual new workstation purchases of $4,583,866 in 2021 were significantly higher than the $1,611,867 that was projected in Case No. U-20963 due to additional workstation and monitor purchases required as a result of the COVID-19 pandemic.[1387] After adjusting for this, the total Company four-year historical average for 2021 through 2024 is $1,817,867, with an electric allocation of $1,246,512, compared to the total Company projection of $1 million each year for 2026 and 2027.[1388] Ms. Baker stated that based on this projection, the

[1382] 6 Tr 4348-4349.
[1383] 6 Tr 4349.
[1384] 6 Tr 4349.
[1385] 6 Tr 4349.
[1386] 3 Tr 766-769.
[1387] 3 Tr 769.
[1388] 3 Tr 769.

Company does not have any adjustments to the projected 2026 and 2027 ARP-WAM costs.[1389]

In its initial brief, Staff repeats arguments made regarding the ARP-FDAM project, asserting that the Company failed to provide Staff with sufficient information to validate the use of the four-year historical average for projecting new device purchases and noting that Staff does not know why the Company no longer uses People and Culture hiring estimates as part of its projection.[1390]

In reply briefing, the arguments presented by both Consumers and Staff mirror their respective arguments relating to the ARP-FDAM project (see above).[1391]

As with the ARP-FDAM project, which was subject to a similar dispute, this PFD finds that the Company's projected costs based on a four-year historical average (with an appropriate adjustment for 2021 costs) are reasonable and prudent. The Commission reached this same result in Case No. U-21806.[1392] This PFD therefore declines to adopt Staff's proposed disallowance.

iii. Digital Infrastructure Automation

Ms. Baker testified that the Digital Infrastructure Automation project will require $382,043 of capital (ROM-adjusted amount) and $159,902 of O&M in the test year.[1393] She stated that the project will automate the deployment, maintenance, and tear down or decommissioning of cloud and data center services, leveraging increased cloud

[1389] 3 Tr 769.
[1390] Staff brief, 57-60.
[1391] Consumers reply, 3-4; Staff reply, 5.
[1392] See September 30, 2025 order in Case No. U-21806, pp. 122-124.
[1393] 3 Tr 736.

capabilities to improve the efficiency, quality, and speed-to-market of customer-facing and internal IT services while reducing operational costs.[1394]

Staff witness Zichi recommended a full disallowance of capital expenditures and O&M associated with this project.[1395] She stated that although Ms. Baker testified the current manual system is costly and this project will lead to a reduction in operational costs, the Company failed to quantify this reduction.[1396] She testified that through audit, the Company stated there will not be a reduction in operational costs and this project will instead provide efficiency and avoid costs.[1397] In a follow-up audit request, the Company further stated that the project will not result in hard cost savings but will result in operational efficiencies and reduce the current manual process by 80%.[1398] Ms. Zichi testified that the Company failed to support the need for this project due to purported cost reductions, and she questioned why there would not be a reduction in costs if the project will reduce manual efforts by 80%.[1399] She concluded that the Company failed to prove the prudency of this project given its inability to confirm or quantify any related cost reductions.[1400]

Ms. Baker responded in rebuttal that when she initially testified about "reducing operational costs," she intended to state "avoiding operational costs."[1401] She testified that the operational efficiencies and avoided costs from this project were addressed in the project synopsis included in her direct testimony, and she also cited Exhibit A-21 as

---

[1394] 3 Tr 736.
[1395] 6 Tr 4349-4350.
[1396] 6 Tr 4350.
[1397] 6 Tr 4350, citing Exhibit S.14.1, pp. 10-12.
[1398] 6 Tr 4350-4351.
[1399] 6 Tr 4350-4351.
[1400] 6 Tr 4351.
[1401] 3 Tr 770-771.

providing support for the risk mitigation and avoided costs.[1402] Ms. Baker added that this 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.[1403]

In its initial brief, Staff argues that the Company's change in language from "reducing" to "avoiding" does not negate the expected end result, which is monetary cost savings, and the Company should be able to quantify those savings.[1404] Staff further argues that the Company has discussed the anticipated operational efficiencies and avoided operational costs but continues to fall short in quantifying them, which is why Staff recommends disallowing the costs of this project.[1405]

This PFD declines to adopt Staff's disallowance. While Consumers has not quantified the avoided costs it expects to see from this project, this PFD finds the Company has nevertheless adequately justified the need for and benefits of this project. As set forth in the project synopsis and Ms. Baker's rebuttal testimony, in addition to avoiding operational costs, this project is expected to avoid incorrect deployment of infrastructure, reduce the risk of major application failure due to security issues, and bolster the resiliency of infrastructure.[1406] Given the benefits of this project beyond cost savings, this PFD does not find that Consumers' failure to calculate the avoided costs merits a disallowance.

[1402] 3 Tr 771.
[1403] 3 Tr 771.
[1404] Staff brief, 56-57.
[1405] Staff brief, 57.
[1406] See 3 Tr 736-738, 770-771.

iv. ISIS Papyrus 2026 Upgrade

project will upgrade the Papyrus Objects suite of applications to the most recent version available per vendor recommendations.[1407] The Company forecasted ROM-adjusted capital expenditures for this project of $131,000 ($164,499 less 20% ROM adjustment) in the bridge period and $263,199 ($328,999 less 20% ROM adjustment) in the test year, as well as $114,044 of test-year O&M expense.[1408]

Staff witness Zichi recommended a full disallowance of the proposed capital expenditures and O&M expenses for this project.[1409] She testified that when asked through audit what would happen with vendor support and cybersecurity patches if the upgrade was not completed at this time, the Company responded that the vendor would continue to provide support even if the upgrade is not completed now, although the Company expressed concerns about delaying the upgrade.[1410] Consumers also confirmed that the vendor would still provide cybersecurity patches, but they may only apply to future releases.[1411] Staff also asked when the vendor will stop providing support and to clarify whether cybersecurity patches will continue to be available if the system is not upgraded; Consumers reported that the vendor has not established a definitive end date for support of the current version and that historically, support has been provided contingent upon the Company maintaining its annual maintenance

[1407] 3 Tr 722.
[1408] 3 Tr 722, 773; Consumers brief, 149.
[1409] 6 Tr 4351-4352. While Ms. Zichi's request included a disallowance of $164,499 in the bridge period, Ms. Baker in rebuttal noted that Ms. Zichi erred by failing to use the ROM-adjusted amount of $131,600. 3 Tr 773. In briefing, Staff acknowledged the error and revised its request to $131,600. Staff brief, 61.
[1410] 6 Tr 4352, citing Exhibit S-14.1, p. 9.
[1411] 6 Tr 4352, citing Exhibit S-14.1, p. 9.

agreement.[1412] In addition, the Company confirmed that cybersecurity patches will continue to be provided and that the vendor has not identified a specific end date for these patches to users who have not upgraded.[1413] Ms. Zichi concluded that Consumers provided reasoning for why this project could be necessary but failed to provide definitive information as to why completing this upgrade is necessary now.[1414]

In rebuttal, Ms. Baker testified that the Company plans to implement this upgrade in 2026 to mitigate the risk of technology obsolescence.[1415] She explained that maintaining a current software release ensures the application receives critical security patches, vendor-issued fixes, and functional enhancements.[1416] While the vendor has indicated they will continue providing cybersecurity patches, these patches may only apply to future releases.[1417] In addition, cybersecurity patches cannot always be applied to older versions of the software, meaning 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.[1418] Ms. Baker added that the application has not been updated in over two years, and 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.[1419]

[1412] 6 Tr 4352, citing Exhibit S-14.1, p. 16.
[1413] 6 Tr 4352, citing Exhibit S-14.1, p. 16.
[1414] 6 Tr 4352.
[1415] 3 Tr 772.
[1416] 3 Tr 772.
[1417] 3 Tr 772.
[1418] 3 Tr 772-773.
[1419] 3 Tr 773.

In its initial brief, Staff notes Ms. Baker's testimony that cybersecurity patches *may* only apply to future releases and that the Company *may* be required to upgrade to a more recent version of the software to apply certain patches from the vendor.[1420] Staff argues that use of the word "may" indicates that the Company has failed to provide enough proof of the immediate need for this project.[1421] Staff also notes that the application has not been updated in over two years and the Company has not reported any problems with receiving necessary support from the vendor with the current version over the past two years.[1422] Staff concludes that since there are no issues reported with the current version, and the vendor has not given a definitive end date for support, this project is not reasonable and prudent at this time.[1423]

While appreciating Staff's concern with cost savings, this PFD disagrees that these costs should be disallowed based on Staff's rationale that the project is not immediately necessary. The ISIS Papyrus application serves an important role in the Company's correspondence with customers, and the Company has established that failing to upgrade this outdated software will increase the risks of technological obsolescence and exposure to security vulnerabilities. This PFD is therefore not convinced that delaying this project would be reasonable and prudent under these circumstances.

v. SAP S/4HANA

Ms. Baker testified that the Systems, Applications, and Products (SAP) Simplified, Fourth Generation (S/4) High-performance ANalytic Appliance (HANA)

[1420] Staff brief, 62.
[1421] Staff brief, 62.
[1422] Staff brief, 62.
[1423] Staff brief, 62-63.

Implementation project will modernize the Company's current SAP enterprise resource planning (ERP) system through a phased migration to the latest S/4HANA solution.[1424] She stated that completing the project is crucial because mainstream support for the current SAP version ends in December 2027 and the Company's SAP systems will face increased risk of cyber attacks if the project is not executed.[1425] She stated that it will take approximately three years to complete the migration, meaning that if the Company begins the project in 2025, it will extend into 2028 and the Company will be required to purchase extended SAP support for 2028.[1426] Ms. Baker noted that extended support for the current SAP version is only available until 2030.[1427] She testified about the development of the cost estimate for the project, a process that was supported by an independent third party.[1428] She testified that the SAP S/4HANA upgrade is more costly than previous upgrades for several reasons, but she stated that it would not be more cost-effective for the Company to replace its SAP systems.[1429]

The Company forecasted capital expenditures for this project (after ROM adjustments) of $20,391,679 in the bridge period and $34,793,090 in the test year, along with $15,178,194 of test-year O&M expense.[1430]

Ms. Baker explained that the Company is requesting special rate-making treatment to amortize the cloud implementation costs for the Software as a Service (SaaS) solutions that will be part of the SAP S/4HANA Implementation project over a

---

[1424] 3 Tr 740-742.
[1425] 3 Tr 744.
[1426] 3 Tr 744.
[1427] 3 Tr 744.
[1428] 3 Tr 745-746.
[1429] 3 Tr 746-747.
[1430] 3 Tr 740; Consumers brief, 152.

15-year asset life, which will help minimize the impact on customer rates.[1431] She further testified that the Company is requesting to defer the O&M expense associated with this project and recover the expense over the life of the asset.[1432]

Staff witness Zichi recommended that the Commission direct the Company to meet with Staff quarterly to inform them of progress on the SAP S/4HANA Implementation project and to discuss updates on any advancements or setbacks in project implementation; budget adherence; changes to project scope, timeline, or expenses; and any problems with operations or customer interactions.[1433] She also opined that the Company should record any over and under recovery of each projected expense compared to the 80% base (ROM projected investment), to be included in the Company's future rate cases until implementation is complete.[1434]

Mr. Coppola recommended that the Commission fully disallow the bridge-period and test-year capital expenditures for this project.[1435] He testified that although Ms. Baker indicated that the current SAP system needs to be modernized because it will reach end of mainstream support at the end of 2027, the new system will basically replace the same functions of the current system and is clearly a case of forced obsolescence by the vendor in order to sell new software, services, and technology.[1436]

[1431] 3 Tr 747-748. Ms. Baker sponsored Confidential Exhibit A-26, which is the IT S/4HANA Cloud Implementation Costs for the projected 13 months ending April 30, 3037 and provides a summary of projected IT Department investments expenditures. Company witness Daly discusses the Company's request to amortize these costs at 3 Tr 1070, 1080.
[1432] 3 Tr 748-749, citing Exhibit A-12, Schedule B-4. Company witness Daly discusses the Company's request to defer the O&M expense and amortize it over 15 years at 3 Tr 1069-1070, 1080.
[1433] 6 Tr 4355.
[1434] 6 Tr 4356.
[1435] 3 Tr 2502. While Mr. Coppola redacted his testimony regarding the capital expenditures and O&M expense amounts related to the SAP S/4HANA Implementation project, Ms. Baker testified in rebuttal that the Company subsequently declassified that information. 3 Tr 795-796.
[1436] 3 Tr 2500.

Mr. Coppola noted that the Company planned to extend the current system support into 2028 and that such extended support was available until 2030.[1437] He testified that through discovery, the Company stated that it had not asked SAP to extend support through and potentially past 2030, and the Company pointed out that it would need to purchase extended support.[1438] Mr. Coppola opined that the fee charged for extended support was likely similar to what the Company currently pays for system support and that operating the current system past 2030 is a viable solution given that the system is still functioning well and is meeting all the operating requirements of the Company.

Mr. Coppola further testified that the Company has not identified any cost savings or financial benefits for implementation of a new ERP system, and he noted the project has a cost/benefit ratio of negative 1.0, meaning it is not financially justified.[1439] He also stated that the project is currently in the investment planning phase and that the Company planned to issue a request for proposal in May 2025, concluding that it is premature to include any capital expenditures in this case.[1440] Accordingly, Mr. Coppola recommended rejecting the capital expenditures associated with the project, removing the associated O&M expense, and rejecting the Company's proposal to defer the O&M costs.[1441]

In rebuttal, Ms. Baker testified that the Company agreed with the recommendations proposed by Ms. Zichi.[1442]

[1437] 3 Tr 2501.
[1438] 3 Tr 2501.
[1439] 3 Tr 2501.
[1440] 3 Tr 2501-2502.
[1441] 3 Tr 2502-2503.
[1442] 3 Tr 776.

Ms. Baker disagreed with Mr. Coppola's assertion that the current system could operate into 2030 and potentially past that point; she explained that the project will take three years to complete and extended support for the Company's current SAP version is only available until 2030.[1443] She testified that if the project is not executed, there is an increased risk of cyberattacks because SAP has stated that standard patches will not be available after maintenance ends.[1444] Ms. Baker also disagreed with Mr. Coppola's claim that the project was premature, testifying that the investment planning phase only reflected that the project is waiting for funding approval and does not indicate that it is incomplete or lacking information.[1445] She added that a business case was completed and approved for this project prior to consideration for inclusion in this rate case, and she stated that the Company plans to spend the projected expenditures based on the project timeline in this case.[1446] Ms. Baker further testified that in Case No. U-21806, the Commission adopted the ALJ's recommendation to approve the SAP S/4HANA Implementation project, along with the associated requests for deferral of O&M expenses and amortization of cloud computing costs.[1447]

In its initial brief, Consumers reiterates Ms. Baker's arguments for rejecting Mr. Coppola's proposed disallowances. The Company also states that SAP is a critical IT system with modules that support basically every aspect of the Company's business.[1448]

[1443] 3 Tr 797.
[1444] 3 Tr 797-798.
[1445] 3 Tr 798-799.
[1446] 3 Tr 799.
[1447] 3 Tr 799.
[1448] Consumers brief, 152.

It notes that the Commission acknowledged in Consumers' latest gas rate case (Case No. U-21806) the importance of the SAP system to "overall system integrity."[1449]

This PFD recommends approving the SAP S/4 HANA Implementation project and the associated requests for deferral of O&M expenses and amortization of cloud implementation costs.[1450] The Company has agreed to Staff's proposed quarterly meeting and reporting requirements, and this PFD recommends adopting those proposals.

Consistent with the Commission's decision in Case No. U-21806,[1451] this PFD declines to disallow the project as recommended by the Attorney General. The Company has established it would not be prudent to delay this project under Mr. Coppola's rationale that operating the current SAP system past 2030 is a viable option. As Ms. Baker explained, advanced planning is required because migration to the new system will take three years to complete, and extended support for the Company's current SAP version is only available until 2030. Further, Mr. Coppola's suggestion that the Company should simply continue purchasing extended support for several additional years is a temporary solution that would only delay the inevitable need to transition to the new system once support is no longer offered. This PFD also finds it is not premature to include the costs of this project in rate base. Consumers explained the importance of this project and described the project planning that has occurred, the alternatives that were considered, and the development of its cost projections. Additionally, the Commission approved spending for this project in Case No. U-21806,

[1449] Consumers brief, 152.
[1450] The Company's request for special accounting treatment is further addressed in the section of this PFD addressing accounting authority and requests for regulatory asset treatment.
[1451] See September 30, 2025 order in Case No. U-21806, pp. 103-107.

finding that the Company had adequately supported its projected expenditures, and there is no basis for a different conclusion here.[1452]

vi. Product Family Enhancements -Customer Projects

Ms. Byrom explained that CX&O Customer Product Family Enhancements are technology improvements in response to the launch of a channel, customer tool, project completion, and/or direct customer feedback; specifically, the enhancements are intended for "the Company's Mobile App, Web Rebate Information for Personalization, and Web Chat AI."[1453] Ms. Byrom characterized the enhancements as flexible, small-scope items using fewer resources than large capital investments to improve functionality, run analytics on platform usage, monitor performance, add customer-driven capability, or address issues as needs arise.[1454]

In addition to listing the benefits of product family enhancement (cost savings and cost avoidance, technology and business process efficiencies, improved customer experience, risk mitigation, safety improvements, and achieving corporate goals), Ms. Byrom stated that the Company must update and maintain the tools preferred by customers.[1455] She characterized the enhancements as neither projects nor operational work, but stated that the three digital tools currently in existence require updating and maintenance, referencing Ms. Baker's testimony as including a detailed breakdown.[1456] The table in Ms. Byrom's testimony indicated that the projected capital expenditure for

[1452] September 30, 2025 order in Case No. U-21806, p. 106.
[1453] 3 Tr 967.21-967.22.
[1454] 3 Tr 967.21-967.22.
[1455] 3 Tr 967.21-967.23.
[1456] 3 Tr 967.22-967.23.

Product Family Enhancements – Customer are $2,365,309 for the projected test year.[1457]

Mobile App

Klocke, a Senior Analyst in the Data Access, Privacy and IT (DAPIT) Section of the Customer Assistance Division (CAD) of the MPSC, presented Staff's recommendation to disallow the funding for the Customer Self-Service Mobile Application (Mobile App or app), a decrease of the $1,056,334 for 2024 and $1,305,671 for 2025, found in Exhibit A-20, lines 14, 112, 193, and 269.[1458] Staff has consistently opposed the mobile app as an unreasonable expenditure because the $10 million project is expensive and unnecessarily duplicates the functionality of Consumers' website.[1459] The app does not include all of the Company website's information, and it is not a necessity.[1460] Furthermore, the Company has not established customer interest in the app. To illustrate, Ms. Klocke pointed to business partner website logins of over 1 million, but only 356,553 app logins, in 2024; this also does not measure what, if anything, was done by customers after logging on.[1461] Prior to the app's launch in 2021, only 169 customers out of 6.8 million expressed interest in the app. While over 1 million customers have now downloaded the app, it constitutes only 28% of Consumers' digital traffic.[1462]

Ms. Klocke noted that the Commission disallowed app costs in Case No. U-20697 in part because only 30% of customers were anticipated to use the app. She

---

[1457] 3 Tr 967.9. See also 3 Tr 735.
[1458] 6 Tr 4324-4325, citing Exhibit S-10.2. 6 Tr 4327.
[1459] 6 Tr 4325-4326.
[1460] 6 Tr 4326.
[1461] 6 Tr 4325-4326.
[1462] 6 Tr 4326-4327.

further noted that the app has been available for several years, but Mobile App "usage has plateaued at under 30%."[1463] The app "has not proved its usefulness and further cost recovery for it should be denied."[1464] Therefore Staff recommends disallowance of $1,056,334 for historical capital costs for 2024, and $1,305,671 for 2025.[1465]

Ms. Byrom replied that duplicate channels for communication with the Company permit customers to "interact depending on their preferences, abilities, and access is reasonable."[1466] She noted that, in approving mobile app spending in Case No. U-21389, the Commission indicated that some redundancy was reasonable, prudent, and had value in meeting customer needs.[1467] Ms. Byrom stressed that the Mobile App and Web Chat AI were both functional and required updates and maintenance.[1468] Furthermore, she testified that Staff "has not pointed to any circumstances that have emerged since" the Commission previously supported these programs. Instead, customer enhancement projects are generally small and "allow for quickly-made changes or fixes, or stem from emergent work."[1469] The Mobile App is in existence and in daily use by customers and must be updated for relevance and accuracy.[1470]

Ms. Byrom reiterated that the app has been downloaded 1 million times; it hosts 29.8% of the Company's digital traffic; and it is the second most commonly used communication channel, with the mobile website in first place. As of September 2025, the app had logged over 2 million outage map views, 100,000 outage reports, and 7.9

[1463] 6 Tr 4327.
[1464] 6 Tr 4327.
[1465] 6 Tr 4327.
[1466] 3 Tr 967.52.
[1467] 3 Tr 967.52, citing the March 1, 2024 order in Case No. U-21389, p. 83.
[1468] 3 Tr 967.54-967.55.
[1469] 3 Tr 967.55.
[1470] 3 Tr 967.56.

million bill payments, with 16.7 million sessions through 2025 projected to increase to 18.9 million sessions in 2026.[1471] Ms. Byrom opined that these statistics establish that the app is popular and useful with increasing interest and use that should be "supported, maintained, and responsive to customer needs."[1472] Similarly, Ms. Baker noted Ms. Klocke's recommended disallowances, and she reiterated the Company's disagreement with Staff's recommendation.[1473]

Consumers' brief largely reflects Ms. Byrom's testimony regarding the Product Family Enhancements.[1474] Consumers emphasizes that the requested enhancements are necessary updates to maintain the app's functionality.[1475] The Company emphasizes Ms. Byrom's testimony regarding the growing usage of the Mobile App, asserting that it is "a popular and useful tool" and that "related enhancement dollars" are reasonable to "support and enrich the Mobile App experience."[1476]

Staff maintains that the mobile app is redundant and duplicative of the Company's website, which is accessible from mobile devices and computers, and which offers more information and functionality than the mobile app.[1477] App usage has plateaued under 30% without the Company proving strong interest in the app. And, even assuming that the app is widely used and should remain available, Consumers has not established that the expenditures will "support and enrich the Mobile App

---

[1471] 3 Tr 967.57.
[1472] 3 Tr 967.57.
[1473] 3 Tr 777-778.
[1474] Consumers brief, 153-154.
[1475] Consumers brief, 154.
[1476] Consumers brief, 155.
[1477] Staff brief, 38.

experience" as the Company claims, which fails the standard delineated by the Commission in Case No. U-21389 for approval of the requested expenditures.[1478]

Staff also contends that the stated purpose for the customer enhancement expenditures are for "emergent work," and that alone is constitutes good reason for disallowing the projected expenditures.[1479] Emergent work presents a risk of over-recovery beyond actual need. In Case No. U-21806, the Commission removed the costs for the Mobile App tied to emergent work on Staff's recommendation, and on the administrative law judge's reasoning in the PFD. The same should be true in this case.[1480]

In Case No. U-21389, the Commission rejected the argument that the Mobile App funding should be disallowed due to being redundant to the website.[1481] Nevertheless, the Commission agreed that the emergent costs that the Mobile App spending represented were akin to contingency expenses that cannot be evaluated for reasonableness and prudence, leading to the disallowance of spending in that case.[1482] In this case, Consumers has not truly established on what the Mobile App enhancements will be spent. To this end, the spending cannot be determined to be reasonable and prudent because it is too speculative to determine whether the projected spending is likely to be reasonably and prudently spent. As a result, this PFD recommends disallowance of $1,056,334 for 2024 and $1,305,671 for 2025 as requested by Staff.

[1478] Staff brief, 38-39.
[1479] Staff brief, 39-40.
[1480] Staff brief, 40.
[1481] March 1, 2024 order in Case No. U-21389, pp. 82-84.
[1482] September 30, 2025 order in Case No. U-21806, pp. 137-139.

LMI Customer Support

Ms. Byrom stated that the Company seeks $1.87 million in capital expenditures for the test year to support the Low Moderate Income (LMI) Customer Support Enhancement project.[1483] She explained that the LMI Customer Support Enhancement project is intended to increase awareness and enrollment in available services, thereby reducing utility bill expenses and the risk of service disconnections from unpaid bills.[1484] She further explained that the project has four core functions, which align with the program's identified goals, steps, and implementation: (1) simplified program enrollment by centralizing enrollment for multiple programs into one process; (2) proactive communication and program awareness, reaching out to customers showing early signs of crisis with assistance options; (3) new and improved LMI offerings, integrating existing programs to provide a more comprehensive support system; and (4) continuous improvement by refining strategies based on customer feedback.[1485] Ms. Byrom testified that more than 1 in every 3 of Consumers' customers is LMI.[1486] By making interactions more accessible, supportive and efficient, and tailoring communications based on behavioral indicators, Ms. Byrom added that the program seeks to increase engagement from 1 in 6 LMI customers, with most of these customers engaging with the Company during a crisis, to engaging 1 in 3 LMI customers, "seek[ing] to increase the likelihood of preventing a crisis through early engagement."[1487]

[1483] 3 Tr 967.26.
[1484] 3 Tr 967.26.
[1485] 3 Tr 967.27-967.29, 967.35-967.36.
[1486] 3 Tr 967.28-967.29.
[1487] 3 Tr 967.27-967.28.

Sergio Cira-Reyes testified on behalf of Urban Core Collective (UCC) as its Climate Justice Catalyst. He outlined the impacts of power generation and utility costs on LMI households, particularly BIPOC communities, with a focus on how service quality, transparency, and public participation could be improved.[1488] Mr. Cira-Reyes stated that the "demand for bill assistance outpaces the outreach efforts and funds from the government to reach energy-insecure households," also opining that the programs are "often difficult to access and insufficient to meet current needs."

Of Consumers' LMI customers, Ms. Byrom testified that 11% are low income, defined as in crisis and unable to pay their energy bill, and 26% are moderate income, identified as being one crisis away from being unable to pay their energy bill.[1489] Most customer interactions come at the point of crisis, limit available solutions, and generally occur at a time when trust is impacted and customers are less receptive to possible solutions.[1490] According to Ms. Byrom, approval of the LMI Customer Support Enhancement project will address the EEAC's and Low-Income Energy Policy Board's priorities by streamlining assistance and enrollment processes, which is also highlighted by Public Act 229 of 2023, instructing utility EWR programs to minimize barriers and overly burdensome verification processes while increasing participation in low-income energy waste reduction programs.[1491] "Overall, this work will provide proactive, immediate information and relief, helping customers manage costs, avoid

[1488] 3 Tr 2281-2305.
[1489] 3 Tr 967.28-967.29.
[1490] 3 Tr 967.29.
[1491] 3 Tr 967.29.

disconnection, and maintain essential services," thereby enhancing "customer well-being with tangible, positive outcomes."[1492]

Broadly, Ms. Byrom testified that the project has been successful since its launch in December 2024, with over 55,000 customers interacting with the tool, and with 12,000 of them, approximately 22%, enrolling in an offering, compared to the .05% of customers who enroll after being contacted by email.[1493] From this, she opined that the LMI project is showing immediate positive outcomes and is a reasonable and prudent investment to support customers. Additionally, it has reduced the Company's need to send approximately 300,000 promotional emails for individual products.[1494] Ms. Byrom clarified that, of the approximately 55,000 customers who engaged with the tool, nearly 30,000 self-identified as LMI, and approximately 40% completed the full eligibility assessment and identified one or more programs for which they might qualify.[1495]

Ms. Byrom added that the majority of users who completed the survey reported that the process was easy to complete, and 56% of users who completed the survey felt that the offerings provided by the tool were extremely personalized or very personalized.[1496] As indicators of success, Ms. Byrom pointed to the tool having captured over 3,000 leads for EWR programs, and that the Green Giving program enrolled six customers within the first hour of its addition to the simplified digital enrollment experience on April 20, 2025, and enrolling 515 low-income customers digitally since, which far exceeds the 10 customers enrolled through agencies in the

[1492] 3 Tr 967.29.
[1493] 3 Tr 967.30.
[1494] 3 Tr 967.30-967.31.
[1495] 3 Tr 967.30.
[1496] 3 Tr 967.31.

same time period.[1497] Ms. Byrom took the position that continued monitoring and feedback collection would allow further refinement and expansion of the tool.[1498]

Ms. Byrom affirmed that customer research was used to develop the LMI project, first using existing research from partners Uplight and Accenture to determine a need for the project, then conducting primary research in the form of surveys, interviews, and ethnographic studies of more than 2,000 LMI customers, 95% of whom lived in Michigan.[1499] The customer research also included solution concept/usability testing; customer panels (survey), including an account dashboard redesign concept preference survey, and including continued text messaging in 2025; in-depth interviews; a card sort/tree test to "[d]etermine information architecture for [the] account dashboard website;" a diary study of 13 non-company LMI customers; and desk research sources Accenture, eSource, Civilla, and Chartwell.[1500]

According to Ms. Byrom, the research findings indicated that 18% of LMI customers did not know how to access help; 36% were unaware they qualified; 25% perceived the process as overly complex and time-consuming; 51% were too overwhelmed to take on another project; 21% considered EWR programs to be price-prohibitive; and 46% were unfamiliar with low-income utility assistance.[1501] Ms. Byrom also cited a 2024 Los Angeles Department of Water and Power case study finding that using income self-attestation increased program enrollment and willingness to initiate

[1497] 3 Tr 967.31-967.32.
[1498] 3 Tr 967.32.
[1499] 3 Tr 967.32.
[1500] 3 Tr 967.32-967.34.
[1501] 3 Tr 967.34.

assistance requests by 40%.[1502] Ms. Byrom asserted that the project would benefit all customers by enhancing energy equity; preventing service cuts, thereby reducing administrative costs and lost revenue by addressing the risk of unpaid bills and service disconnections; building trust with LMI customers, fostering loyalty and increasing a customer's willingness to engage proactively; reducing low-income bill and energy burdens; and engaging LMI households with both bill assistance and clean energy solutions, bolstering environmental sustainability.[1503] The LMI Customer Support Enhancement Project is also exploring ways to assist customers who do not qualify as low-income but may still be facing significant financial issues.[1504]

Ms. Byrom broke down the total $1.87 million expense for the LMI Customer Support Enhancement project: $600,000 for simplified program enrollment; $370,000 for proactive communication and program awareness; $700,000 for new and improved LMI offerings; and $200,000 for continuous improvement.[1505] In pursuing these core functions, the Company intends to integrate existing programs within its energy assistance, payment plan, EWR, DR, and renewable energy portfolios into one, streamlined system.[1506] While Ms. Byrom noted that the Company is evaluating expansion of the programs available under the new and improved LMI offering, the initial launch of the simplified enrollment included five programs: the Home Energy Analysis & Helping Neighbors Program (income qualified); budget plans; customer

[1502] 3 Tr 967.34.
[1503] 3 Tr 967.34-967.35.
[1504] 3 Tr 967.35.
[1505] 3 Tr 967.35.
[1506] 3 Tr 967.36-967.37.

selected due dates; billing and payment alerts; and a link to MI Bridges and 2-1-1 (income qualified).[1507]

While Mr. Cira-Reyes opined that Consumers needs to do more to address assistance gaps in these programs, and he contended that "the Company has not provided concrete details on how or when this project will benefit customers – such as a concrete timeline and a program monitoring and evaluation plan."[1508] He also testified that assistance programs exclude many people struggle with the affordability of their energy bills, and, he contends, use of multiple programs is inefficient, leaves customers unaware of programs and how to qualify and access them. They can also result in program participants receiving less net assistance where, for instance, an LIA or RIA credit is applied to a bill before assistance is calculated under CARE MB.[1509] Tabitha Williams, founder and president of Parents for Healthy Homes, who also testified on behalf of UCC, added that information about programs should be available in several different forms, such as hard copies, online, and real-time phone assistance, to make information accessible.[1510] She indicated that the "shift toward primarily digital customer service creates barriers for much of my community: elderly residents, people with disabilities, families where English isn't the primary language, and those without reliable internet access."[1511]

Brittney Klocke, a Senior Data Analyst in the Data Access, Privacy and IT (DAPIT) Section of the Customer Assistance Division (CAD) of the MPSC, responded to

---

[1507] 3 Tr 967.37-967.38.
[1508] 3 Tr 2310-2312.
[1509] 3 Tr 2311-2313.
[1510] 3 Tr 2391-2392.
[1511] 3 Tr 2396.

Ms. Byrom's testimony, stating that, despite repeated requests for information from Staff, and audit responses from Consumers demonstrating how the project will function, Consumers had not demonstrated clear, tangible results from the LMI Customer Support Enhancement.[1512] Staff recommended disallowance of the LMI Customer Support Enhancement, which is $525,246 for the bridge period ending 2025 and $1.87 million in capital expenditures for 2027.[1513] It is unclear to Staff why $600,000 is needed to simplify enrollment when this creates no new programs.[1514] It is also unclear to Staff why $370,000 is needed to make customers aware of program options through the Proactive Communications and Program Awareness when those options are already presented on Consumers' website and on other mailings.[1515]

In Staff's opinion, Consumers has not demonstrated that the $120,000 to $370,000 in targeted outreach campaigns will be able to reach customers who are potentially in crisis. According to Ms. Klocke, the Company's definition of customers in crisis does not adequately capture "customers who *could* end up in crisis," and that "all customers, not just those identified by the Company as low-to-moderate income, should have access to all the information the LMI project provides."[1516] This is best accomplished through Consumers' existing website and/or mailings.[1517]

Ms. Klocke testified that Staff also finds $700,000 very costly for New and Improved LMI Offerings to redesign and integrate existing programs, as well as offer comprehensive support to help identify best options for reducing energy burdens

---

[1512] 6 Tr 4328.
[1513] 6 Tr 4327.
[1514] 6 Tr 4328-4329.
[1515] 6 Tr 4329-4330.
[1516] 6 Tr 4330.
[1517] 6 Tr 4330.

without extensive searching. It is unclear what new offerings and ongoing maintenance, plus annual updates, would be necessary, and what costs, on top of the $700,000, would be incurred over time.[1518] Addressing the fourth core function of the LMI project, Continuous Improvement and Feedback, Staff objects to the $200,000 to establish metrics and collect data on performance and feedback metrics because Consumers has not "demonstrated why this function will cost so much."[1519] Per Staff, the Company does not acknowledge that it is proposing spending for a new way to disseminate information that is already available to customers.[1520]

Staff expressed additional concerns. For instance, the Company had a small sample size for their LMI project survey, conducting six "usability tests" with 104 participants, only 56 of whom were Michigan residents.[1521] The "Self-Identification Validation" survey consisted of 1,967 customers, and 60 LMI customers surveyed regarding the account dashboard redesign.[1522] Only 13 LMI participants, who were not themselves Consumers customers, were the subjects of the "diary study to generate broad LMI insights"[1523] Although Consumers' goals of "fulfilling the priorities of the EAAC and the Low-Income Energy Policy Board" are laudable, Ms. Klocke testified that Consumers had not convinced Staff that a project anticipated to cost at least $2 million with "vague benefits" was "the correct way to fulfill those priorities."[1524] She reiterated that Staff recommends full disallowance of the LMI Customer Support Enhancement

[1518] 6 Tr 4330-4331.
[1519] 6 Tr 4331-4332.
[1520] 6 Tr 4332.
[1521] 6 Tr 4332-4333.
[1522] 6 Tr 4333.
[1523] 6 Tr 4333.
[1524] 6 Tr 4333.

project. Ms. Klocke concluded by noting that her analysis was not included in Staff's revenue deficiency, and that this would be addressed in Staff's brief.[1525]

Ms. Byrom responded that the LMI Support Enhancement project was conceived because: only 1 in 6 LMI customers engaged in assistance programs; 36% of customers assumed they were not eligible for utility payment assistance; 33% did not know assistance was available; and 18% did not know how to apply.[1526] This led to development of the project's four core functions.[1527] Ms. Byrom testified that the $600,000 funding request for the Simplified Enrollment's User Flow is to continue development, testing, and maintenance of the digital tool to reduce barriers for LMI customers, not only providing program information but assisting customers in enrolling. This "fills a critical gap in the Company's current service model that goes beyond simply making the information available," improving ease of access for "customers who need it most."[1528] In response to Mr. Cira-Reyes's testimony regarding barriers to program participation disproportionately affecting low-income households, Ms. Byrom opined that the LMI Enhancement project is geared to address these challenges, and that disallowance of the project would defer "meaningful relief," perpetuating "fragmented systems that are not meeting the needs of customers."[1529]

Ms. Byrom further testified that the Commission supported the LMI Enhancement project in its September 30, 2025 order in Case No. U-21806. Although the Commission issued the caveat that it expected to see substantial progress in the Company's website

---

[1525] 6 Tr 4333-4334.
[1526] 3 Tr 967.61.
[1527] 3 Tr 967.62.
[1528] 3 Tr 967.62.
[1529] 3 Tr 967.63.

redesign project, it found the goal of simplifying and streamlining LMI customer access to support to be a reasonable and prudent goal.[1530] Ms. Byrom listed progress markers for the project, including that: 78,000 customers had engaged with the LMI tool, with 52,000 self-identifying as LMI, adding customer data that Consumers did not have previously; 35% of those individuals completed the full eligibility assessment, with one or more qualifying programs identified; 25,000 customers have completed the enrollment flow, with almost 20% enrolled in more than one offering; 69% of customers surveyed rated the tool as "extremely easy to use," and customer feedback has been positive; the tool has reduced the need to send over 300,000 promotional emails to reach enrollment goals; and that the addition of the Green Giving option matched the six total agency enrollments from the prior six weeks in the first hour, and has since resulted in 515 LI customers being digitally enrolled in Green Giving.[1531]

Ms. Byrom opined these results demonstrate that the tool has been effective in reducing enrollment barriers, increasing program visibility, and helping LMI customers more easily access necessary support, and that monitoring and feedback would continue to improve and expand the tool.[1532] She answered Mr. Cira-Reyes' criticisms by testifying that Consumers "must balance investment into infrastructure, safety, and reliability with the need for assistance" within current funding and administrative constructs.[1533] She added that the LMI Simplified Enrollment flow was intended to address information and sign-up gaps, as well as guide customers to the programs that best fit their needs, in answer to his criticisms regarding a lack of information and

[1530] 3 Tr 967.63-967.64, citing September 30, 2025 order in Case No. U-21806, p. 144.
[1531] 3 Tr 967.64-967.65.
[1532] 3 Tr 967.65.
[1533] 3 Tr 967.65.

customers who enrolled in multiple programs ultimately receiving less assistance as a result. Ms. Byrom testified that the steps necessary to sign up for payment assistance programs are necessary at the State level to ensure income threshold compliance.[1534]

Consumers' brief emphasizes that the LMI Customer Support Enhancement seeks to ease enrollment and awareness of assistance program eligibility for LMI customers through its Simplified Program Enrollment, Proactive Communication and Program Awareness, New and Improved LMI Offerings, and Continuous Improvement.[1535] It further emphasizes that one third of customers are LMI, but only one in six are in Energy Assistance programs, with most customers in or near crisis when interactions seeking assistance begin. The brief repeats that primary and secondary research was used to develop the project, and it otherwise reflects Ms. Byrom's testimony regarding the project.[1536]

Consumers, unsurprisingly, disagrees with Staff's recommendation to fully disallow the $1.87 million for test year, and $525,246 for bridge period, capital expenditures for the LMI Customer Support Enhancement. In relation to Simplified Enrollment, Consumers indicates that Staff is wrong to assume that the project merely makes it more clear where customers can find and enroll in programs, with the project instead "guiding customers through eligibility and enrollment for multiple programs," instead of clicking multiple links and completing multiple eligibility forms.[1537] In relation to Proactive Communications and Program Awareness, while the Company agrees with Staff that general outreach is helpful, the LMI project "will use a planned methodology to

[1534] 3 Tr 967-65-967.66.
[1535] Consumers brief, 155.
[1536] Consumers brief, 155-156.
[1537] Consumers brief, 156-157.

inform targeted communication … to anticipate needs, align with customer motivations and preferences, and drive stronger engagement with better outcomes."[1538] Website redesign alone will not accomplish this goal.[1539]

Consumers went on to explain that the New and Improved LMI offerings is intended to create a programming and technological infrastructure to support new and responsive LMI offerings, including how programs fit together, identifying gaps in services, and bringing services together to provide an efficient customer experience.[1540] Continuous Improvement and Feedback is intended to actively monitor usage patterns and collect feedback to enhance and expand the tool's performance and capabilities, and not just, as Staff contends, to collect data from customers.[1541] Consumers' brief again notes the level of customer engagement and enrollment success as evidence that the project has value for customers.[1542]

Staff's brief clarifies that Staff is recommending reducing low moderate income customer support enhancements by $525,000, which is a $385,000 reduction to rate base, and is also recommending LMI "customer support enhancements #2 capital expenditures by $1,870,000, which is a $8,42,000 [sic] reduction to rate base," because it is not clear how the program will assist LMI customers.[1543] Staff contends that the project has not been shown to increase customers' experience or enhance financial stability.[1544] Instead, the project is spending over $2 million to connect customers to

[1538] Consumers brief, 157-158.
[1539] Consumers brief, 158.
[1540] Consumers brief, 158.
[1541] Consumers brief, 158-159.
[1542] Consumers brief, 159-160.
[1543] Staff brief, 40-41.
[1544] Staff brief, 41.

existing programs by providing information that is already available on Consumers' website.

According to Staff, over 53,000 customers did not complete the enrollment flow, after engaging with the tool, and only 35% of customers completed the full eligibility assessment and identified one or more programs for which they qualify.[1545] The customer feedback touted by the Company in support of the program is a "shockingly low" percentage of LMI customers.[1546] Consumers offers only generic responses regarding streamlining and enhancing customer experience without providing long-term solutions for LMI customers. Staff contends that Consumers has "not do[ne] its due diligence on this project and ha[s] many missed opportunities to seek information from" LMI customers "regarding what will help them in the long run."[1547] To Staff, none of this supports claims that the LMI tool is meeting its goals, or that spending on the project is necessary and prudent.[1548]

Staff raised these issues in Case No. U-21806.[1549] While stating that it expected to see "real progress" in relation to the Company's website redesign project, the Commission found the benefits of a streamlined and simplified process to be a priority, and it found the project spending to be reasonable and prudent in trying to increase customer access to information and assistance programs.[1550] This PFD sees no reason to deviate from this, and recommends allowance of the LMI Customer Support Enhancement project capital expenditures.

[1545] Staff brief, 41-43.
[1546] Staff brief, 43.
[1547] Staff brief, 43.
[1548] Staff brief, 42-44.
[1549] September 30, 2025 order in Case No. 21806, pp. 140-143.
[1550] *Id.,* p. 144.

Web Chat AI

Ms. Byrom set forth the same reasons and benefits for enhancements to Web Chat AI as she did for the Mobile App, indicating that the enhancements were necessary for ensuring the Web Chat AI functions as "requested or expected," and that this required updating and maintenance.[1551]

Ms. Klocke presented Staff's recommended disallowance of spending for the Web Chat AI project, $157,574 in capital expenditures for the partial bridge year ending April 30, 2026, and $315,148 in capital expenditures for the partial year ending December 31, 2026; she also recommended disallowance of $19,896 in O&M for the partial year ending December 31, 2026.[1552] The Web Chat AI tool is intended to use existing information, much of which is already available under the frequently asked questions page of the Consumers website, and is intended to act as an "easily searchable comprehensive high-level Frequently Asked Questions."[1553] According to Ms. Klocke, complex questions will still require escalation to a customer service representative during business hours, rendering moot the all-hours availability of the tool. The chat tool offers no cost savings. Staff does not see the value of the project when it offers only costs and information already available on the Consumers' website without genuinely adding to the self-serve options available to customers.[1554]

In rebuttal, Ms. Byrom testified that Web Chat AI "is a valued customer channel of choice," that is in the early stages of enhancement, and its cost savings have not yet

[1551] 3 Tr 967.22-967.23.
[1552] 6 Tr 4334.
[1553] 6 Tr 4335.
[1554] 6 Tr 4336.

been quantified due to its newness.[1555] Ms. Byrom referred to previous citations by Consumers to JD Power findings regarding chat tools, with that organization publishing that 42% of online customers prefer live chat to email, with email favored by only 23% of customers. The development and maintenance of chat tools is "not driven by utility preference," but the needs and expectations of customers.[1556] In conclusion, Ms. Byrom noted that peer institutions like DTE Energy have similar tools with similar hours. Ms. Baker's rebuttal testimony refers to Ms. Byrom's and repeats that the Company does not agree with Staff's proposed disallowance of capital expenditures for the project.[1557]

Staff's brief reiterates the recommendation to reduce Web Chat AI capital expenditures "by $473,000, which is a $278,000 reduction rate base."[1558] It succinctly states that "Staff's position is that the web chat AI tool offers technology that is redundant, offers no cost savings, and brings little value to the Company's customers."[1559] Staff's brief largely recapitulates Ms. Klocke's testimony and recommendation, adding, in response to Ms. Byrom's rebuttal testimony, that the same common queries to be addressed by Web Chat AI can also be found through a simple search of the website, and that more complex inquiries will still require a call to a customer service representative during regular business hours. Consumers provides no feedback or support for the program from its own customers, and references to peer

[1555] 3 Tr 967.58.
[1556] 3 Tr 967.58.
[1557] 3 Tr 780.
[1558] Staff brief, 44.
[1559] Staff brief, 44.

companies ultimately lead users to a frequently asked questions page on DTE Energy's website, and an error message for AEP Energy's website.[1560]

In response to Consumers, Staff recharacterizes its direct testimony, pointing out that there is value in improving customer self-serve abilities, but still concluding that the AI chatbot is not prudent or useful in doing this. As a result, Staff sees no value in Web Chat AI.[1561] Staff points out that the Commission disallowed the requested costs for Web Chat AI in Case No-U-21806, where the Company had not yet redesigned its website despite having repeatedly received funding approval for doing so, and that the scope and purported benefits of the program have not changed between that case and this one.[1562] Staff emphasizes that there are no cost savings anticipated from the Web Chat AI program, which is the Company's primary metric for success.[1563]

While admitting that the cost savings of Web Chat AI "are unquantified at this time" due to the program being in the "preliminary stages of enhancement," Consumers, in its brief, contends that the program provides instant, "24/7 customer support" to common inquiries, potentially eliminating service center calls and instantly providing relevant information.[1564] It is not intended to have all of the Consumers' website's functionality, and it is not intended to replace the website, but instead is intended to provide better customer self-service and increase access to assistance and programs. Consumers again cited the live chat statistics from JD Powers.[1565]

[1560] Staff brief, 44-46.
[1561] Staff brief, 46.
[1562] Staff brief, 47.
[1563] Staff brief, 45-46.
[1564] Consumers brief, 160-161.
[1565] Consumers brief, 160-161.

The respective parties' positions appear largely unchanged from those they set forth in Case No. U-21806.[1566] In that case, the Commission adopted the ALJ's findings that Consumers had provided only industry research, but no Consumers-specific data, or data regarding Consumers' ratepayers and their interest in such a tool, further concluding that the chat function would not provide anything new or innovative.[1567] The Commission also remarked that it "expect[ed] to see real progress by the company on its website redesign project before being asked to revisit this issue in a subsequent rate case."[1568]

In this case, no such progress has been established, Staff reports that Consumers' references to peer organizations with similar programs are overblown, and no new Consumers-specific data has been introduced to support approval of the program. It is not clear who, if anyone, is actually being helped with this spending. As a result, this PFD recommends disallowance of spending for the Web Chat AI project, $157,574 in capital expenditures for the partial bridge year ending April 30, 2026, and $315,148 in capital expenditures for the partial year ending December 31, 2026. In the appropriate section, this PFD will also be recommending disallowance of $19,896 in O&M for the partial year ending December 31, 2026 for the reasons set forth for disallowance of the capital expenditures.

Web Dashboard Redesign

Overlapping with the simplified enrollment from the LMI project, Ms. Klocke recommended disallowance of the Web Dashboard Redesign in the amount of

[1566] September 30, 2025 order in Case No. U-21806, pp. 135-137.
[1567] *Id.*, pp. 136-137.
[1568] *Id.,* p. 137.

$500,000 because it is redundant and unnecessary. The need for the redesign, particularly at the forecasted expense, is unjustified. Staff recommended disallowance, even if the LMI project is not disallowed, because "the requested expenditures for the Web Dashboard Redesign project" overlaps with the LMI project.[1569]

In response, Ms. Byrom again opined regarding the benefits of the LMI project, adding that the Web Dashboard Redesign would "provide personalized information to all customers on a standard landing page," providing "a second opportunity for LMI customers to find the information they need."[1570] She touted the transparency that web dashboard redesign would provide to customers regarding programs in which they were already enrolled, program eligibility, and EWR, payment offerings, and DR initiatives.[1571] Nevertheless, Ms. Byrom testified that the Company "is removing the related dollars in this case" for the Web Dashboard Redesign.[1572]

Ms. Baker clarified for Consumers that it disagreed with Ms. Klocke's rationale for removing the spending for the Web Dashboard Redesign, but that the Company was agreeing to the removal of $525,246 in capital expenditures for the 12 months ending December 31, 2025 "[d]ue to other higher priority work" resulting in the Web Dashboard Redesign enhancement not being completed as planned.[1573] Staff recognizes this concession in its brief.[1574] Consumers' brief goes into some detail, asserting that the redesign is on hold during the transition to the S4HANA platform.[1575] With the

[1569] 6 Tr 4337.
[1570] 3 Tr 967.59-967.60.
[1571] 3 Tr 967.6.
[1572] 3 Tr 967.59.
[1573] 3 Tr 780-781.
[1574] Staff brief, 63.
[1575] Consumers brief, 161-162.

Company's agreement in the outcome, this PFD recommends removal of $525,246 in capital expenditures for 2025 for the Web Dashboard Redesign project.

Web Rebate Personalization

Staff recommended full disallowance of Product Family Enhancements – Customer Capital Web Rebate for Personalization "in the amount of $87,541 for the partial bridge year ending 4/30/2026 and $175,082 in capital and $16,580 in O&M for the partial test year ending 12/31/2026.[1576] According to Ms. Klocke, Consumers was unable to provide more information than a brief audit response regarding information about the program and its underlying costs. While the Company indicates that this program would customize relevant rebates to the individual, and help with affordability by informing customers of rebates, Ms. Klocke notes that the Company's website already offers a general rebate search option, and Consumers provides direct marketing of rebates that may be a good fit for individual customers; these should provide customers with sufficient information.[1577] Additionally, project costs were based on "high-level work effort of 2,500 hours."[1578] Staff questioned the reasonableness of cost estimates based on "conjecture," especially where the project is not expected to reduce costs in any other area of the Company.[1579]

In rebuttal, Ms. Byrom maintained that the Web Rebate personalization would benefit customers by helping them find rebates that fit their needs. However, despite

[1576] 6 Tr 4337-4338.
[1577] 6 Tr 4338-4339.
[1578] 6 Tr 4339.
[1579] 6 Tr 4339.

this benefit, she stated that the Company "is removing the related dollars in this case."[1580]

Ms. Baker clarified that, while the Company disagrees with Staff's rationale for disallowance as presented by Ms. Klocke, the Web Rebate Personalization enhancement will not be completed as planned, again due to "other higher priority work."[1581] As a result, Ms. Baker stated that the Company agrees to the removal of $175,082 in capital expenditures for the partial test year ending December 31, 2026, and O&M expense of $87,541 for the partial bridge period ending April 30, 2026, and $11,053 in IT Investments O&M for the partial test year ending December 31, 2026.[1582] This is repeated in Consumers' brief, and recognized in Staff's brief.[1583] With the apparent agreement of the Company, this PFD recommends adoption of Staff's disallowance of capital expenditures for the Web Rebate Personalization project.

vii. Projects in the Investment Planning Phase

Mr. Coppola recommended the removal of $7,731,000 for the bridge period and $14,495,000 for the projected test year from Consumers' IT capital expenditures based on his identification of nine premature projects.[1584] He also recommended the removal of $3,136,000 from the projected test year O&M expense.[1585]

Mr. Coppola categorized the nine projects into two groups. Group 1 included: 1) Electric Geographic Information System (GIS) Design Platform Modernization; 2) Electric GIS Utility Network Transformation; 3) Integrated Energy Management Platform

---

[1580] 3 Tr 967.60.
[1581] 3 Tr 782.
[1582] 3 Tr 782.
[1583] Consumers brief, 162-163. Staff brief, 63.
[1584] 3 Tr 2499.
[1585] Id.

Optimization; and 4) Service Restoration Artificial Intelligence (AI).[1586] Group 2 projects included: 1) Critical Substation Upgrade; 2) Data & Analytics Platform Rationalization; 3) OT Datacenter Migration; 4) Forward Web Proxy Services; and 5) Physical Access Management and Alarm Response.[1587]

As to these nine projects, Mr. Coppola testified that they are still in the "investment planning" phase and Consumers failed to provide "additional cost data, specific project justification, and the phase of project development" in response to discovery requests.[1588] Mr. Coppola concluded that "significant uncertainty remains whether or when they will advance further," such that the projects are too premature to include in this rate base as customers should not pay for the depreciation and return on project cost that may not materialize within the forecasted time frame.[1589]

Ms. Baker testified in rebuttal that Mr. Coppola's reductions would impact the capital expenditure and O&M spending shown in confidential Exhibit A-20 and Exhibit A-12, Schedule B-5.1.[1590] She asserted that Mr. Coppola uses a "broad brush" to reduce IT costs without considering the value these projects create or recognizing the "requirement work" necessary to develop the business case for IT projects, such as identifying high-level business requirements and determining whether the functionality needed is already present in Consumers' IT environment.[1591] Ms. Baker testified further that because a project is in the "investment planning" phase does not mean that it is incomplete or lacking information, rather this is where a project remains while it is

---

[1586] 3 Tr 2497.
[1587] 3 Tr 2498.
[1588] 3 Tr 2497-2498; Ex. AG-27 and Ex. AG-29.
[1589] 3 Tr 2497-2498.
[1590] 3 Tr 785-786, 788-789.
[1591] 3 Tr 786-789, 674-675.

waiting for funding after the business case for the project is completed and approved.[1592]

Ms. Baker referred to the testimony of other Company witnesses to support the four Group 1 projects. Mr. Kelly provided the scope, benefits, alternatives considered, and costs for the Electric GIS Design Platform Modernization and Utility Network Transformation projects to support the Company's distribution strategy.[1593] He testified that the Electric GIS Utility Network Transformation project will transform Consumers' current GIS platform to the Environmental Systems Research Institute (ESRI) Utility Network Model and establish a unified HVD, LVD, and substations data model, which will optimize core engineering and operational processes, technologies, and data.[1594] He testified that the Electric GIS Design Platform Modernization replaces the existing LVD design software with a platform that will fully integrate into Consumers' ESRI R GIS platform and allow engineering teams to have a single source and format to view asset data, construction drawings, and redlines and it will improve data quality and reduce waste.[1595]

Mr. Snider described the Service Restoration AI project and its costs and benefits.[1596] He testified that Consumers has developed several "use cases," such as storm declaration, resource planning and utilization, and asset identification, where AI can assist with faster and more consistent service restoration decision making.[1597] He stated that "[t]he Company estimates an annual opportunity of reducing each medium-

---

[1592] 3 Tr 787, 790.
[1593] 3 Tr 1490-1494.
[1594] 3 Tr 1490.
[1595] 3 Tr 1492-1493.
[1596] 3 Tr 2152-2155.
[1597] 3 Tr 2153-2155.

to-catastrophic event by 4 hours, with an estimated savings of $4.5 million annually with the realization of all use cases."[1598]

Ms. Jerore supported the Integrated Energy Management Platform Optimization project. She testified that the project is an important part of Consumers' PCI Platform, which it uses to communicate with MISO to buy and sell electricity in the wholesale market.[1599] She asserted that the project will allow Consumers to migrate from an on-premise PCI platform to a cloud-based platform and will create value by: 1) using the vendor's SaaS environment to provide efficient operational support; 2) freeing up resources for more value-add work; 3) reducing the need to maintain the Oracle server footprint; 4) reducing IT labor support costs; and 5) reducing ongoing networking equipment replacement and upgrade costs.[1600] She asserted that once the funding is approved the Integrated Energy Management Platform Optimization project is expected to move forward as planned.[1601]

As for the Group 2 projects identified by Mr. Coppola as being premature, Ms. Baker summarized her direct testimony on the five projects:

1. 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.

2. 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

[1598] 3 Tr 2155.
[1599] 3 Tr 1795.
[1600] 3 Tr 1795-1796.
[1601] 3 Tr 1801.

redundant support and licensing burdens, improve data accessibility and governance, and enable scalable, cloud-aligned analytics capabilities.

3. 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.

4. 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.

5. 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.[1602]

She maintained that these projects should not be dismissed based simply on being in the investment planning phase, rather the intangible value of the projects, such as avoided costs, safety, and quality, must be considered.[1603] She added that Consumers has taken measures to address the concerns of over recovery of IT projects, including by taking a proactive 20% Rough Order of Magnitude (ROM) reduction in the Company's initial investment forecast.[1604]

Ms. Baker specifically addressed the Critical Substation Upgrade, Data & Analytics Platform Rationalization, and OT Datacenter Migration projects. She made a correction to the projected ROM-adjusted test year capital for the Critical Substation

[1602] 3 Tr 791 (citations omitted).
[1603] 3 Tr 790-791.
[1604] 3 Tr 788, 792.

Upgrade project, asserting the correct amount should be $2,798,533 and not $3,135,966.[1605] She added that if the Commission adopts Mr. Coppola's recommendation to remove this project, his recommended capital disallowance should be reduced by $337,433.[1606] She also maintained that the Data & Analytics Platform Rationalization project has completed the "planning" phase and is now in the "execute" phase, with plans for the first release to go live in December 2025.[1607]

She asserted that Consumers has provided more robust support for the reasonableness and prudence of the OT Datacenter Migration project, as suggested by the Commission in Case No. U-21806 when it adopted the ALJ's recommendation to disallow the project based on insufficient justification to relocate the datacenter in comparison to fixing the problems in the existing building.[1608] According to Ms. Baker, if Consumers is to remain in the basement of the Parnall building, it must fix the aging climate control equipment and the persistent water filtration issues, which the Company estimates will cost $5,082,728.[1609] She asserted that relocating the datacenter will avoid this cost and mitigate the risk caused by the basement's proximity to a main water pipe.[1610] She also contended that the Parnall building's nearness to a railway is inappropriate for a datacenter due to vibration issues and the environmental hazards from train cargo. She testified that the industry standard, ANSI/BICSI 002-2024, recommends maintaining a distance of 1,600 meters or more to ensure long-term stability and minimize risk, while the distance from the railway to the Parnall building is

---

[1605] 3 Tr 793.
[1606] Id.
[1607] Id.
[1608] 3 Tr 793-794, citing Case No. U-21806, Order, Sept. 30, 2025, p. 130.
[1609] 3 Tr 794.
[1610] Id.

approximately 170 meters.[1611] Lastly, she contended that if the OT Datacenter Migration project were approved, Consumers would be able to avoid future costs in the ARP-OT Support Common and ARP-OT Support Electric projects.[1612]

Consumers' brief reiterates Ms. Baker's testimony, while the Attorney General's brief elaborates on Mr. Coppola's testimony, however, she withdraws the recommendation to remove the costs for the Data & Analytics Platform project identified in Group 2 of Mr. Coppola's recommended disallowances.[1613] She rejoins Ms. Jerore's testimony that the Integrated Energy Management Platform Optimization project is valuable and necessary and will move forward as soon as funding is approved, stating that it does not address the prematurity of including the project in rate base.[1614] She contends that if Consumers was confident about the project it would proceed with development, but the Company's response indicates that Consumers is not confident about the value of the project and wants to place the project development risk on customers.[1615] She adds that this lack of confidence is likely due to the fact that the project's Benefit to Cost ratio is a negative 1.0, meaning that it has no financial benefits and is not economically justified.[1616] The Attorney General's updated recommendation is the removal of $4,904,000 for the bridge period and $11,983,000 for the projected test year from the Company's forecasted capital expenditures, as well as $3,136,000 from the projected test year O&M expense.[1617]

[1611] Id.
[1612] 3 Tr 795.
[1613] AG initial brief, p. 105-108, fn. 334.
[1614] Id., p. 106.
[1615] Id., p. 106-107.
[1616] Id., p. 107; Ex. AG-75.
[1617] Id., p. 108.

Consumers' reply brief counters the Attorney General's assertion that it is not confident in the value of the Integrated Energy Management Platform Organization and refers to Exhibit AG-75 as indicating that the project will lower costs and is crucial to the provision of utility service.[1618] Consumers states that "the project will provide cost savings as part of an expense that is necessary for the Company to meet a FERC requirement and therefore should be approved."[1619]

This PFD declines to adopt the Attorney General's blanket recommendation to disallow these projects because they are in the "investment planning phase," and premature. While agreeing with the Attorney General that customers should not have to pay for uncertain and premature projects, this PFD disagrees that a project in the investment planning phase is per se premature. This PFD notes that the Commission has not found that a project's designation as being in this phase is dispositive as to the reasonableness and prudence of the project for inclusion in rate base.[1620] A review of Exhibits AG-27 through AG-29, provided by the Attorney General to support the recommended disallowances, shows that many of the projects have Board approval and completed BCAs, and all but two of the projects have planned 2026 expenditures. Further, the Attorney General stated that Consumers did not provide detailed cost information for the projects in discovery, but it does not appear that she requested this information for all the projects. Other than the projects being premature and uncertain, the Attorney General does not offer any other reason to deny these projects.

[1618] Consumers reply brief, p. 4.
[1619] Id.
[1620] See e.g., Case No. U-21806, Order, Sept. 30, 2025, p. 130 (declining IT projects in the Investment Planning Phase, but for other reasons).

This PFD finds that Consumers has provided sufficient support for each project in Group 1 and Group 2, including the need for the project, its benefits and costs, and alternatives considered. As for the OT Datacenter Migration project, this PFD notes that Consumers responded to the Commission's order in Case No. U-21806 and provided the costs to remain in the basement of the Parnell building and why a railway line near the building is problematic for a datacenter. However, while this PFD finds that Consumers generally supported the need for the Electric GIS Utility Network Transformation project and the Integrated Energy Management Platform Optimization project, this PFD finds that these projects are premature based on Consumers' indication that it does not plan to expend funds for these projects until 2027, the last four months of the test year.[1621] Based on the foregoing, this PFD recommends that the Commission reject the Attorney General's disallowances and approve the updated test year expenditures provided by Consumers for all Group 1 and Group 2 projects except for the Electric GIS Utility Network Transformation ($1,050,000 capital and $520,000 O&M) and Integrated Energy Management Platform Optimization ($1,075,000 capital and $508,000 O&M) projects, resulting in a recommended disallowance of $2,125,000 in capital expenditures and $1,028,000 in O&M expenses for the projected test year.

7. Demand Response Capital Expenditures

Mr. Gast testified that Consumers projects $1.56 million in DR capital expenditures for the test year as set forth in Exhibit A-12, Schedule B-5.5.[1622] Mr. Gast spoke to the Company's proposed DR surcharge and reconciliation process.[1623] He also

[1621] See AG-28.
[1622] 3 Tr 1092, 1096, 1111.
[1623] 3 Tr 1099-1101.

presented the Company's DR portfolio of both residential and business DR programs, and introduced the Company's proposed Whole Home Optimization Demand Response pilot.[1624] According to Mr. Gast, the capital expenditures are primarily the device cycling switches installed for the residential program, and customer communication equipment to inform customers of the necessity to perform during events, with remaining customers receiving manually triggered communications by Consumers' employees.[1625]

Mr. Gast opined that the DR program helps manage peak demand capacity, protects the grid at times of emergency and severe weather, and avoids the cost of additional generation infrastructure to serve peaks while providing the Company with flexibility at the same time as meeting climate and IRP goals.[1626] He testified that DR provides an opportunity for customers to take control of their energy usage, decrease energy costs, and participate in Consumers' Clean Energy Plan.[1627] According to Mr. Gast, Consumers intends to focus on its most cost effective programs while introducing a DR pilot proposal to gather information on the expansion of new technologies.[1628]

Ms. Jerore, formerly Ms. Metz, indicated that the DR programs fall into two categories, those directed by Consumers, supplying either a fixed quantity or range of energy, and those dependent on customer behavioral choices, with the programs driving energy reduction by rate structures incentivizing reduced use during peak loads.[1629] The latter category is estimated to be 1,023 MW for 2025/2026 and 1,144 MW

[1624] 3 Tr 1110-1111.
[1625] 3 Tr 1097.
[1626] 3 Tr 1097-1098.
[1627] 3 Tr 1098.
[1628] 3 Tr 1098.
[1629] 3 Tr 1793.

for 2026/2027.[1630] Ms. Jerore testified that capacity of the DR resources to be registered with MISO for summer 2025/2026 is approximately 651.4 zonal resource credits (ZRCs), with a $62 million estimated market value, and 684 ZRCs for planning year 2026/2027 with an estimated market value of $65 million.[1631]

Mr. Gast discussed the three residential demand response programs: 1) Residential Device Cycling, a program with over 95,000 participants representing 57.3 MW of enrolled capacity at the end of 2024; 2) Dynamic Peak Pricing (DPP), offering pricing that incentivizes reduced energy use during peak hours, with 176,000 participants and representing 37.9 MW of enrolled capacity at the end of 2024; and 3) Residential Smart Thermostat, using cloud-based software to optimize customer Wi-Fi thermostat settings for energy savings, with 59,000 participants and 54.2 MW of enrolled capacity at the end of 2024.[1632]

Mr. Gast also described the two DR business programs, the Commercial and Industrial (C&I) Contractual DR, and the Business DR Rate Options, also called C&I Rate options, including General Interruptible (GI) and General Interruptible 2 (GI2) rate provisions, Rate Energy Intensive Primary (EIP), and Long-Term Industrial Load Retention Rate (LTILRR). At the end of 2024, these programs had enrollment of approximately 39 accounts and 259.5 MWs of capacity.[1633] He explained what would happen for these customers if a DR event is called, as well as how this effects MISO portfolio capacity.[1634]

[1630] 3 Tr 1794.
[1631] 3 Tr 1793-1794.
[1632] 3 Tr 1095, 1103.
[1633] 3 Tr 1095-1096, 1106.
[1634] 3 Tr 1106-1109.

CEO witness Kenworthy did not oppose Consumers' DR programs, but he advocated that virtual power plants (VPPs) were more reliable, and encouraged Consumers to use its DR program, particularly its Smart Thermostat Program, as the foundation for future VPP operations.[1635] These points are repeated in the CEOs' briefs,[1636] along with the assertion that Mr. Kenworthy's recommendations are "effectively unrebutted."[1637] Mr. Boehnke and GLREA raise some similar issues.[1638] MEIU is more measured, indicating in Mr. Albers' rebuttal testimony that any new VPP program that may be developed leverage and scale existing DR programs.[1639] Both Mr. McPhail and Mr. Kelly present reasons why the Company opposes Mr. Kenworthy's and Mr. Boehnke's VPP recommendations.[1640] For the reasons articulated by the Company, this PFD declines to adopt the intervenors' VPP recommendations in relation to the Company's DR program.

Regarding what the Company is proposing, Mr. Gast described the DPP program changes, and the program's two pricing options, Critical Peak Pricing (CPP) and Peak Time Rewards (PTR), both with the goal of encouraging customers to shift their energy consumption during a DR event. The Company is proposing to eliminate the enrollment incentive for the PTR program, reduce customer demand savings for PTR from 0.21 kW per customer to 0.13 kW per customer, and to reduce the PTR credit from $1/kWh of

---

[1635] 4 Tr 3203-3212.
[1636] CEO brief, 5-10. CEO reply, 1-2.
[1637] CEO brief, 9.
[1638] 4 Tr 3323, 3327-33228. GLREA brief, 31-32.
[1639] 6 Tr 4238-4240, 4242. MEIU reply, 3-4.
[1640] 3 Tr 1748-1752. 3 Tr 1608-1612.

energy reduced during event hours to $0.50/kWh, as well as a reduce CPP from 0.25 kW per customer to 0.18 kW per customer.[1641]

These changes stem from the Company, with its third-party evaluator Cadmus, predicting a lower capability by half than the 2022 planning value that had been previously used; therefore, the Company determined that the credit offered to customers should also be halved.[1642] Mr. Gast stressed the importance of the PTR program as a no-risk customer option to participate in DR, with 153,147 enrolled participants in 2024, and the highest rate of low-income enrollment. The Company sees PTR as a "gateway" program, used to "upsell" PTR participants into more cost effective DR programs, particularly Smart Thermostat.[1643] As part of the Company's attempts to use PTR as an entry-level or gateway offering, Mr. Gast stated that Consumers has reduced program expenses to improve cost-effectiveness, is working to discontinue customer enrollment incentives, and focusing on low to no cost marketing.[1644]

On behalf of MEIU, Mr. Sproul outlined his understanding of Consumers' DR programs, including a table in his testimony listing the number of participants and enrolled capacity in MW by program.[1645] According to Mr. Sproul, discovery responses from the Company indicate that there are 2,255 low-income customers enrolled in the CPP program, and 17,450 low-income customers enrolled in the PTR program,

---

[1641] 3 Tr 1104-1106. As discussed by MEIU's Mr. Sproul, the 0.18 KW for the CPP program, and the 0.13 kW for the PTR program, are their capability values at 90 degrees Fahrenheit for the customer demand savings predicted to be achieved. 6 Tr 4209.
[1642] 3 Tr 1105.
[1643] 3 Tr 1105-1106.
[1644] 3 Tr 1105-1106.
[1645] 6 Tr 4197-4207.

approximately 13% of the customers enrolled in the programs.[1646] Customers participating in the DPP program benefit through reduced energy costs and greater control over their energy usage.[1647]

Mr. Sproul described the 2022 Cadmus study referenced by Mr. Gast, as well as the 2025 Cadmus presentation based on the 2022 DR events that focused on the cost-effectiveness of the PTR program, forming the basis for Consumers' proposed cuts to PTR and CPP credits to improve cost-effectiveness. Mr. Sproul further discussed the BCAs and the proposed cuts themselves.[1648] He added that, according to discovery responses, the 2024 BCA completed in relation to the Company's 2024 DR reconciliation compared the levelized cost of the program to 75% of CONE, which the Company considered to be the primary benefit of the DR program. This showed DPP having the lowest levelized cost of $24,491/MW, with Device Cycling having a levelized cost of $193,671/MW, and Smart Thermostat having a levelized cost of $134,565.[1649] When weighted for the amount of MISO-registered MW, benefit-cost showed that DPP program net benefits for 2024 were $927,554, versus a negative $2,163,045 for Device Cycling and negative $823,484 for Smart Thermostat.[1650]

Mr. Sproul, however, believed the Company's net benefit calculations could be inaccurate and not representative of the CPP and PTR programs because they were based on the 2022 Cadmus study values tested in four different settlement scenarios to improve PTR program cost effectiveness [minimum threshold, cap on credits, rounding

---

[1646] 6 TR 4206-4207.
[1647] 6 Tr 4206.
[1648] 6 Tr 4207-4214.
[1649] 6 Tr 4213, citing Exhibit MEIU-2.11.
[1650] 6 Tr 4213-4214.

down of per kWh savings to the nearest integer, and reduced incentive rate].[1651] He posited, however, that these were outdated, as evidenced by the fact that they were based on five DR events in 2022 when average enrollment for the CPP program was 14,177 and 77,019 for PTR; participation has grown to 24,860 for CPP and 173,559 for the PTR program. Mr. Sproul thought it "reasonable to assume that the per customer demand savings values" would thus differ between 2022 and 2025.[1652] He noted that Cadmus itself recommended Consumers review performance annually under planning conditions to verify long-term trends, but Consumers had not done this, and there had not been a DR event to analyze since 2022.[1653]

As a result, Mr. Sproul recommended denial of Consumers' proposal to reduce the per customer demand savings values for the PTR and CPP programs until the Company performed an updated analysis of the programs' performance under current planning conditions.[1654] Similarly, Mr. Sproul believed the proposed PTR bill credit reduction from $1/kWh to $0.50/kWh to be unjustified. He thought it likely that reducing the bill credit by half would change customer behavior by reducing the incentive to change. Despite Consumers acknowledging the risk of changed customer behavior, the Company's assumed cost savings were based on assumptions that consumer behavior would remain unchanged.[1655] Mr. Sproul thought it "premature to propose such a drastic

[1651] 6 Tr 4210-4211.
[1652] 6 Tr 4214-4215.
[1653] 6 Tr 4215.
[1654] 6 Tr 4214, 4216, 4219.
[1655] 6 Tr 4216-4217.

change" without "any data to support how changing the incentive" would change customer behavior.[1656]

Similarly, Mr. Sproul opined that changing the DPP program when it already appeared to be cost effective could undermine or sabotage it, which was unjustified for a program with a proposed surcharge of $0.002009 per kWh annually - a relatively low cost.[1657] He also disagreed with discontinuing PTR program customer enrollment incentives based on Mr. Gast's testimony that the PTR program was a gateway to other DR programs, with Mr. Sproul contending that there was "no merit in discontinuing the use of customer enrollment incentives" and shifting to no cost marketing channels, based on the overall cost-effectiveness of the program.[1658] He thought that the shift could eliminate the incentives that turned the PTR program into a gateway DR program.[1659]

In response, Mr. Gast reiterated that reducing customer demand savings is intended to match the expected demand reduction with actual demand savings, and that "[r]elying 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," ultimately hurting Consumers' ability to economically serve its load.[1660] Although he agreed that the programs had changed after the 2022 Cadmus study, Mr. Gast opined that this served to increase the "need to reduce expected demand savings per customer," because increased enrollment would result in "larger total actual demand savings during

---

[1656] 6 Tr 4217, 4219.
[1657] 6 Tr 4217-4218.
[1658] 6 Tr 4218.
[1659] 6 Tr 4218-4219.
[1660] 3 Tr 1114-1115.

an event."[1661] He added that discontinuing the PTR customer enrollment incentive contributes to DR portfolio cost-effectiveness and "limits enrollment, making future events more cost effective," noting that an enrollment incentive could be reintroduced at a later date if enrollment needed a boost.[1662]

Mr. Gast testified that the current increased PTR enrollment necessitated a reduction in the PTR bill credit to limit the cost of calling an event.[1663] Consumers' brief clarifies that projected capital costs for the residential DR programs are $1,375,000 for the test year, and as found in Exhibit A-12, Schedule B-5.5, line 2. The brief otherwise highlights the contents of Mr. Gast's testimony about the nature of the residential DR programs and the need for the proposed CPP savings and PTR credit reductions.[1664] Although Consumers broadly accepts Mr. Sproul's position that using 2022 data is flawed, the Company comes to the opposite conclusion as Mr. Sproul, maintaining that program changes since 2022 have only increased the need to reduce demand savings per customer.[1665] The Company implies that, because more people have enrolled in the CPP and PTR programs, the customer demand savings must be reduced to avoid increasing event payout.[1666] Consumers urges rejection of Mr. Sproul's recommendation that Consumers' proposed residential DR changes be suspended until the Company updates its CPP and PTR analyses because "the Company has evaluated

[1661] 3 Tr 1115.
[1662] 3 Tr 1115.
[1663] 3 Tr 1115.
[1664] Consumers brief, 167-169, 173-175.
[1665] Consumers brief, 173.
[1666] Consumers brief, 173.

its options and is looking to ensure it is not using outdated 2022 planning values during future events."[1667]

In answer to Mr. Sproul's testimony that the Cadmus survey did not adequately consider changes to customer behavior in relation to a reduced PTR bill credit, Consumers answers that customer behavior is not a primary concern for the PTR program because its goal is to provide an entry offering to the DR program. The Company's goal is to move customers away from that program to "more predictable demand savings."[1668] The PTR program's value is in bringing people into DR, and a decrease in cost-effectiveness would undermine that value.[1669] Additionally, the brief echoes Mr. Gast's testimony that the Cadmus study's prediction of lower future DPP capability necessitates lowering the credit, adding that this presents a balanced risk of customers adjusting their behavior due to the reduced credit.[1670]

Consumers further contends that, while PTR may be a lower cost option, it "generally has lower kW savings per participant than CPP and lower demand savings overall."[1671] Notably, when defending the reduced PTR bill credits, argues that the overall cost-effectiveness of DPP is "somewhat buoyed by CPP."[1672] The Company is "trying to prevent … increased enrollment [that] could further negatively impact the cost-effectiveness of PTR (and DPP altogether) because of the asymmetrical cost and average payment being higher than average performance."[1673] To this end, Consumers

---

[1667] Consumers brief, 173-174.
[1668] Consumers brief, 173-174.
[1669] Consumers brief, 174.
[1670] Consumers brief, 173-174.
[1671] Consumers brief, 173-174.
[1672] Consumers brief, 174.
[1673] Consumers brief, 174-175.

responds to assertions that PTR is already cost-effective by stating that the "current cost-effectiveness of the program should not prevent the Company from taking steps to further increase the cost-effectiveness of the program."[1674] And the Company again remarks that it could reintroduce incentives to raise enrollment if necessary in the future.[1675]

MEIU summarizes its position as "it appears that Consumers is proposing to take an already cost-effective [residential DR] program with a low per-MW cost and drastically cut the incentives behind it, risking its continued viability."[1676] MEIU clarifies that, through discovery, the reduction of the PTR credit was developed "by compositing a 2022 Cadmus study (the "2022 Study") and a 2025 Cadmus "Presentation on PTR Alternative Settlement Investigation" (the "2025 Presentation").[1677] The reduced estimated demand savings projections for the existing PTR program, and the distribution of impacts and bill credits from the 2022 DR events were imported into four different alternatives to improve PTR program cost effectiveness, including the 50% reduced incentive rate as an example. However, the 2025 Presentation stated that reducing incentives could improve cost-effectiveness, but it could also result in diminished participant response.[1678]

MEIU largely reiterates Mr. Sproul's testimony, including that 13% of the PTR and CPP program participants qualify as low income, and that Consumers has no data

[1674] Consumers brief, 175.
[1675] Consumers brief, 175.
[1676] MEIU brief, 19.
[1677] MEIU brief, 18, Citing 6 Tr 4207-4212.
[1678] MEIU brief, 18.

on whether changing the incentive amount would change customer behavior.[1679] The brief also cites Mr. Sproul's common-sense conclusion that a 50% reduction in the PTR bill credit will likely reduce customer incentives to adjust behavior, and that the proposed PTR incentive payment reduction is based on outdated information.[1680] MEIU discounts Mr. Gast's testimony that higher enrollment would result in a higher cost of calling an event, instead arguing that the higher cost would be offset by larger total demand savings, particularly where PTR customers are only paid for the kWh of electricity that they reduce over and above their baseline usage. MEIU maintains that the proposed changes to the demand savings values for the PTR and CPP programs should be denied until they are based on a performance analysis rooted in current planning conditions.[1681] MEIU's reply brief adds no new arguments.[1682]

This PFD recommends that the Company be permitted to discontinue enrollment incentives for the PTR program. Although the burden is on the Company to establish whether their actions are reasonable and prudent, both the Company and MEIU provide reasonable courses of action. Additionally, the Company is not wrong when it says that a new incentive can be offered if enrollment needs to be increased in the future.

The reduction of the PTR and CPP compensation for existing program customers is a different matter. The Company glosses over that the CPP program is currently cost-effective enough to carry any possible shortfall from the PTR program.[1683] There is no data on the impact that the proposed reduction might have on customer behavior; there

[1679] MEIU brief, 15-21.
[1680] MEIU brief, 19-20.
[1681] MEIU brief, 20-21.
[1682] MEIU reply, 6.
[1683] Consumers brief, 174.

is no projection of cost effectiveness based on current program enrollment; but there is data that the CPP program is currently cost effective. As a result, this PFD recommends that the proposed reduction to the CPP program capability values from 0.25 kW per customer to 0.18 kW per customer be rejected until the Company provides current information in a future rate case filing regarding the actual impacts of the change based on reasonably current enrollment numbers, as well as reasonably current cost benefit projections.

The proposed reduction of the customer demand savings for PTR from 0.21 kW per customer to 0.13 kW per customer, and the reduction of the PTR credit from $1/kWh to $0.50/kWh, is a closer question. Again, the Company has not provided adequate information regarding the reduction in capability values based on current information. This PFD recommends that the reduction in capability value to 0.13 kW per customer be denied. However, it will be the Company that will lose flexibility and the positive effects of the PTR program with MISO during a DR event if it has underestimated the impact of the reduced credit on customer behavior. This PFD recommends that the PTR bill credit reduction to $0.50 be adopted.

Finally, no party has actually objected to the $1,375,000 in proposed spending for residential DRR. As a result, this PFD recommends it be approved.

Turning to the Whole Home Optimization DR pilot, Mr. Gast presented the Company's request for inclusion of $750,000 within the total capital expenditures, included in Exhibit A-12 and discussed in Exhibit A-182, for the pilot. Of this, $200,000 is to be allocated to load management devices, $200,000 allocated to multifamily whole unit optimization, $150,000 to single family whole home optimization, and $200,000 to

smart analytics and aggregation through whole home smart optimization.[1684] Mr. Gast testified that the pilot will allow Consumers to test customer response and interaction with energy usage and demand analytics, to test customer-controlled responses and behavior, and to test aggregation of resources within a home using whole home optimization.[1685]

Specifically, Mr. Gast testified that the Company is testing technology with time-of-use (TOU) "rate structures (RSP 1001, RSH 1040, and RPM 1050), to quantify energy savings impacts, and to understand the barriers customers face with adopting DERs in the home, including battery storage and electric vehicles, to shift energy off-peak."[1686] The Company intends to work with implementation contractors, third-party evaluators, software vendors, and hardware vendors to install and test multiple available technologies to assess cost-effectiveness, demand reduction, energy waste reduction, customer interest, and technical integration feasibility.[1687]

Mr. Kenworthy was generally supportive of the pilot, but believed it should be a "steppingstone" to integrating the technologies being tested into a broader portfolio, and ultimately be used as the first phase of a VPP.[1688] This position is repeated in the CEOs' brief.[1689] The CEOs' reply brief clarifies that they seek an order directing Consumers to create a VPP *plan,* and not a VPP, based on its DR program and the Whole Home Optimization Pilot.[1690]

[1684] 3 Tr 1109-1110.
[1685] 3 Tr 1110.
[1686] 3 Tr 1110.
[1687] 3 Tr 1110.
[1688] 4 Tr 3216-3217.
[1689] CEO brief, 8-12.
[1690] CEO reply, 2-4.

Staff witness Towslee noted that Consumers has indicated that it will provide updates on this pilot in future electric rate and DR reconciliation cases, that the Company has stated it will notify Staff and intervenors of significant changes from the approved plan, and that Consumers will provide the results of its completed evaluation.[1691] Mr. Towslee testified that "Staff looks forward to reviewing the findings and requests," particularly requesting detailed data for discrete and aggregated time periods, pilot costs, allocation of remaining funds, energy savings attributable to the pilot, and assessments of cost-effectiveness.[1692] Staff also requested that the next rate case or DR filing include more information about the specific technologies being tested and how those technologies would be evaluated in order to better inform potential future programs. Finally, Staff requested that Consumers "provide discussion of its intentions for any necessary transition or integration of the pilot participants once the pilot concludes at the end of 2028."[1693]

Mr. Gast responded that Consumers was "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."[1694] This was repeated in Consumers' brief.[1695] Staff repeats its request for information, as well as the Company's apparent agreement, in its own brief.[1696]

[1691] 6 Tr 4494, 4496.
[1692] 6 Tr 4496-4497.
[1693] 6 Tr 4497.
[1694] 3 Tr 1113.
[1695] Consumers brief, 170-171.
[1696] Staff brief, 185-186.

This PFD recommends approval of the pilot, including the requested capital expenditures, noting that there was no opposition to the proposal. This PFD further sees no reason not to recommend that Staff's information requests be accommodated. Consumers is already willing to provide the requested information, and the data will be informative for the pilot, development of future programs, and the integration of the pilot into a permanent program if that becomes advisable. This PFD notes, however, there is currently no basis for forcing Consumers to use the program to institute a VPP, or to use the pilot to formulate a VPP program, and this PFD declines to recommend this, particularly before the pilot has collected any data.

Lastly, Mr. Gast outlined the Company's DR surcharge and reconciliation process, indicating that Consumers had calculated a separate revenue requirement for the DR program including all DR capital, O&M costs, and DR related credits in the Company's rate design. He represented that the surcharge, which he indicated had also been proposed in DR reconciliation Case No. U-21906, to take effect with the 2026 filing of the 2025 DR reconciliation proposing new spending for 2027, would account for changing costs, over/under-recoveries, and recovery of the performance incentive, and would use the DR surcharge methodology during the annual reconciliation that was approved by the Commission in Case No. U-21585.[1697] He further stated that the "Company used the calculation methodology in the ongoing DR reconciliation proceeding, Case No. U-21906, to request surcharges."[1698]

[1697] 3 Tr 1099, 1101.
[1698] 3 Tr 1099-1100.

Mr. Gast proposed that the DR capital and O&M expenditures be included in the annual DR plan and reconciliation instead of the general rate case, with the annual DR reconciliation filing operating as both a DR plan and a DR reconciliation in order to mitigate regulatory lag and reduce the complexity of addressing DR in multiple cases.[1699] He added that the Company had presented DR capital and O&M expenditures in the instant case in the event that the DR regulatory construct was not approved. With the exception of credits remaining in rate design, DR would otherwise be removed from the instant rate case if the surcharge were approved.[1700]

To this end, Ms. Connolly testified that Exhibit A-16, Schedule F-2.1, line 2, reflects the removal of the $43,572,000 DR revenue requirement calculated by Mr. Daly and set forth in A-83, and allocated to each rate schedule by Ms. Davis[1701] in Exhibit A-89. Ms. Connolly indicated that this approach was approved in Case No. U-21585.[1702] Mr. Daly's testimony intertwines with Ms. Connolly's, noting that Exhibit A-83 calculates the projected test year revenue requirement for DR programs with those programs included in this case, summarizing the total projected test year revenue requirement for DR programs, and then breaking this down into the projected test year revenue requirement for the commercial and industrial DR program.[1703] Mr. Daly noted that adjustments to either capital or O&M spending for DR would require an update to Exhibit A-83.[1704] And Mr. Daly noted that the revenue requirement for DR is removed

[1699] 3 Tr 1099-1101.
[1700] 3 Tr 1100- 1101.
[1701] Emily Davis testified regarding the DR surcharge allocation in COSS. 4 Tr 2664.
[1702] 3 Tr 154, 162.
[1703] 3 Tr 1075-1076.
[1704] 3 Tr 1075-1076

from the base rates calculation, with recovery of the DR revenue requirements occurring through the surcharge, was approved in Case No. U-21585.[1705]

Mr. Towslee indicated that Staff supports some changes to the existing DR framework but took the position that such changes should be considered in Case No. U-21637, which is intended to "investigate opportunities for improving the process by which [the Commission] reviews applications filed under" MCL 460.6a.[1706] Furthermore, the Commission directed in that case that comments regarding a new DR process be submitted no later than September 10, 2025. Therefore, Staff opined that Case No. U-21637 was more appropriate than the current rate case for consideration of DR process changes, or consideration of Consumers' "suggested changes to the regulatory construct."[1707] In its brief, Staff reiterates the request that the PFD and the Commission defer changes to the DR regulatory construct to Case No. U-21637, indicating that modifications to the three-phase DR approach are already being considered there. Staff stresses that DR is an important capacity resource, and that a standardized process for DR for all electric utilities is more appropriate than utility-specific strategies.[1708]

MEIU's Mr. Sproul recognized that the cost of the DR programs is incorporated into the Company's COSS using the production capacity allocator 220. He opined that DR programs are a capacity resource, and should be treated like other capacity resources, in line with best practices and previously approved methodology.[1709] He took note of the DR programs' revenue requirement, citing Exhibit A-83 regarding the

---

[1705] 3 Tr 1076.
[1706] 6 Tr 4497-4498.
[1707] 6 Tr 4498.
[1708] Staff brief, 186-187.
[1709] 6 Tr 4201-4202.

revenue requirements of $21,321,000 for residential DR, $22,251,000 for C&I DR, and $43,572,000 total DR programs.[1710] Mr. Sproul commented that the Company is proposing to remove the total revenue requirement to a DR surcharge, with the surcharge to be allocated among residential, commercial secondary, lighting and unmetered, and rate general self-generation rate classes, to be adjusted through its DR reconciliation proceedings, with a DR surcharge rate for residential customers initially set to $0.002009 per kWh.[1711] Because of scant information on the impact that this could have, Mr. Sproul did "not have a specific position at this time."[1712] Nevertheless, he recommended that any decision on the DR surcharge methodology and process be consistent with the rate case procedures docket, Case No. U-21637.[1713]

Mr. Gast responded that the Company would need to make any DR changes by its May 2026 DR filing, noting, "[i]f 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."[1714]

Similarly, Consumers' brief indicates that, "[c]onsistent with the Commission's Order in Case No. U-21585 the Company calculated a separate revenue requirement for the DR Program including all DR capital, O&M, and rate credits" to be adjusted in the DR reconciliation proceeding.[1715] The Company asserts that no one has objected to the surcharge, therefore it should be approved. The Company also repeats the points

---

[1710] 6 Tr 4202.
[1711] 6 Tr 4202-4203.
[1712] 6 Tr 4203.
[1713] 6 Tr 4203.
[1714] 3 Tr 1114.
[1715] Consumers brief, 171.

raised in Mr. Gast's testimony that the timing of the changes in relation to the 2026 DR process would need a Commission order before May 2026, so the Commission should approve the proposed changes to the regulatory process to reduce lag between surcharge implementation and reconciliation.[1716]

The Commission addressed this issue in its December 18, 2025 order in Case No. U-21637. In that case, while Consumers expressed support for moving DR to a separate proceeding, noting its proposal in this case, the City of Ann Arbor, the Attorney General, DTE, and Staff all expressed reservations with this approach. Staff proposed either that DR could be moved into a separate proceeding with either a surcharge or deferred accounting mechanism, or "that DR could be moved entirely into the rate case" with each utility filing "a final DR reconciliation wherein a final balance would be determined and recovered in a subsequent rate case," allowing "the reconciliation process to end and all DR costs to be included in subsequent rate cases."[1717]

The Commission adopted Staff's latter proposal, finding "that the rate case option recognizes that DR is more akin to generation investments and should be part of the holistic view that occurs in rate cases … [t]he Commission directs the Staff and the utilities to hereafter include DR in rate cases after a final reconciliation has taken place under the existing construct."[1718] Although noting that this would likely take two years to implement, the Commission found "that the advantages associated with moving the

[1716] Consumers brief, 172-173.
[1717] December 18, 2025 order in Case No. U-21637, pp. 8-10.
[1718] December 18, 2025 order in Case No. U-21637, p. 10.

entire DR rate approval process to rate cases outweigh any inconvenience associated with the delay."[1719]

As a result of the Commission's order in Case No. U-21637, this PFD recommends that Consumers' proposed surcharge and reconciliation process be denied. While cognizant of what the Company might see as whiplash from its interpretation of the Order in Case No. U-21585, Consumers should be directed to move towards bringing DR entirely within its rate case filings as soon as possible to effectuate the Commission's directives in Case No. U-21637.

8. Customer Experience and Operations Capital Expenditures

Ms. Byrom presented Customer Experience and Operations (CX&O) expenditures. CX&O is divided into Customer Interactions and Billing & Payment. Customer Interactions include phone, Interactive Voice Response (IVR), website, mobile app, and digital correspondence, i.e. text messages. Billing & Payment includes billing, payment processes, and personalized payment plans or settings for individual customers.[1720] Ms. Byrom went on to briefly outline the interplay between CX&O and the IT department, outlining test year capital and O&M for IT-related CX&O projects.[1721] The contested Product Family Enhancements - Customer Projects, such as the mobile app, are discussed elsewhere in this PFD, as are related O&M matters.

Ms. Byrom testified that, based on a financial forecast of the work plan and designated development activities within the Analytics and Outreach, Customer, Billing, and Credit Assistance areas, CX&O capital expenditures for direct work were $1.25

[1719] *Id.*
[1720] 3 Tr 967.8.
[1721] 3 Tr 967.9.

million in the historical year, are projected to be $693,000 for the bridge period, and are projected to be $1.87 million for the test year, with the projected test year amount attributed entirely to customer interactions.[1722] These capital expenditures do not appear to be contested, and this PFD recommends their approval.

9. Corporate Services Capital Expenditures

Mr. Foster presented the Company's Capital Expenditures for Corporate Services.[1723] He testified that Corporate Services included costs to equip and support Learning & Development and the Corporate Services areas primarily at Company headquarter locations with office furniture and equipment.[1724] The 2024 actual capital expenditures were obtained from the Company's records and projected using non-labor inflation rates.[1725] As shown in Exhibit A-12, Schedule B5.4, Consumers projects Corporate Services Capital Expenditures of $1,378,000 in the bridge period and $1,064,000 in the test year. These expenditures do not appear to be in dispute, and they should therefore be approved.

10. Transportation Electrification Plan

Mr. Myrom proposed enhancements to Consumers' Transportation Electrification Programs ("TEPs") intended to improve customer experience and benefits without any budgetary increase from prior MPSC approvals.[1726] He used the term electric vehicle ("EV") to collectively describe all forms of EVs, including battery electric vehicles ("BEVs") and plug-in hybrid electric vehicles ("PHEVs"). Mr. Myrom testified that no

---

[1722] 3 Tr 3, 5. Exhibit A-12, Schedule B-5.3.
[1723] 6 Tr 3353.
[1724] 6 Tr 3361-62.
[1725] 6 Tr 3362; Exhibit A-12, Schedule B-5.4.
[1726] 3 Tr 1860.

additional spend from prior approvals was requested, but the timeline has changed due to factors such as National Electric Vehicle Infrastructure ("NEVI") contracting delays and the Federal Highway Administration's decision to suspend EV charging infrastructure funding. These factors have extended the completion date for multiple projects.[1727] He further noted that the positive net present value (NPV) clearly showed that the additional load growth from EVs creates margin that exceeded the TEPs revenue requirement and other costs. Thus, the TEPs do not increase rates but instead mitigate rate pressure for all customers.[1728]

Mr. Myrom testified that the Company TEP was centered on long-term strategies to optimize EV charging load to the benefit of all customers, and investments, incentives, programs, and expenditures that were reasonably expected to increase transportation electrification in the Company's electric service territory. The Company's latest TEP was publicly available online and, while filed prior to the final order in Case No. U-21492, it was recognized by the Commission as sufficient for planning purposes until July of 2026, by which time an updated TEP will be filed by the Company.[1729] He noted that the Company continues to support utilizing a portion of the additional revenue from EV load growth to pay for TEPs. As such, EV drivers fully pay for the TEPs, while all customers benefit from the load optimization as the same infrastructure was used to power more EVs, generating additional revenue that mitigates rate pressure.[1730] The Company has been highly successful at optimizing EV load growth via its TEP,

[1727] 3 Tr 1860-61.
[1728] 3 Tr 1862; Exhibit A-165.
[1729] 3 Tr 1862.
[1730] 3 Tr 1863.

exceeding the State goal of 80% or more off-peak charging and making the Company's TEP a national model for EV load management.[1731]

To optimize load and increase EV adoption, Mr. Myrom testified that the Company was focused on three key strategic program areas within the TEP umbrella – Residential, Public and Fleet.[1732] For residential, Mr. Myrom noted that being able to reliably and cost-effectively charge at home was critical for most EV drivers.

The single-family programming implemented a combination of educational outreach, Time-of-Use ("TOU") rate, and rebate and incentive programs for off-peak charging at Level 2 ("L2") circuit levels of 50 amps or less (40 amps continuous for 14 9.6 kW) consistent with residential design standards. The up to $500 rebate (up to $1,000 for income-qualified customers) served to get EV drivers engaged with their utility, then the monthly off-peak charging incentive of $10 (for 12 months) helped reinforce off-peak charging behavior. The residential team implemented a referral incentive program to grow enrollment and the dual-cord L2 and splitter incentive, which was designed to prevent EV charging peaks beyond the residential design standards by continuing to utilize a single 50 amp circuit (40 amp continuous) as additional EVs are purchased or leased (a likely occurrence given that most EV drivers remain EV drivers) to spread the load over a longer off-peak time at a maximum 9.6 kW load.[1733]

For multi-family homes, Mr. Myrom noted that the Company also focused on providing equitable charging opportunities at apartments, condos, and townhomes where charging infrastructure was known to be harder to implement. In multifamily

[1731] 3 Tr 1863-64.
[1732] 3 Tr 1864.
[1733] 3 Tr 1864-65.

situations where a customer's residential L2 could not be directly tied to their meter and parking location, the Company offered up to a $7,500 rebate to add a separate service with at least two plugs powered by 100 amps. The Company also provided signs for display at the charger encouraging off-peak charging, literature for property managers relaying the same message, and a $20 per month bill credit for 12 months when 80% or more of charging was off-peak.[1734]

Mr. Myrom asserted that public charging advanced both grid optimization and EV adoption. Grid optimization could be achieved by incentivizing lower-power charging (L2 and L1) at strategic off-peak locations that fit the customer's use case. Public charging also assisted with EV adoption because knowing a charger existed where you want to travel instills charging confidence. Public L2 and L1 programs also utilized educational outreach materials and signage for site hosts, TOU rates, and rebates for off-peak charging of up to $7,500 per two L2 plugs or five L1 plugs powered by 100 amps. The Company also asserted that community charging promoted equity, encouraging developers to reach areas that might otherwise lack access to lower-power charging by creating L2 infrastructure within walking distance of multifamily residences.[1735]

Fleet and workplace charging also directly addressed grid optimization and EV adoption. The fleet program focused on outreach, TOU rate, and rebate programs for small and medium businesses, local governments, non-profits, and educational institutions to incentivize off-peak charging. The additional funding for fleets serving income-qualified customers continued to allow non-profits and local governments to add

[1734] 3 Tr 1865-66. 1386-87.
[1735] 3 Tr 1866-67.

cost-effective EVs to their fleet that they may not have been able to afford without the funding. The Company offered fleet and workplace rebates of up to $7,500 per two plugs powered by 100 amps, with an enhanced rebate of up to $10,000 for workplace L2 that also served as community charging locations overnight and on the weekend. Fleet also offered a long-duration direct current ("DC") rebate of up to $15,000 per plug of 50 kW or less, focused on medium and heavy-duty vehicles such as electric school buses that have larger batteries and need a higher power level to complete their charging cycle off-peak.[1736]

Mr. Myrom then testified that TOU rates were not enough to optimize off-peak charging without TEP programs as a negligible number of EVs enroll in the Company's TOU rate without engagement. He asserted that relying on TOU rates alone was highly ineffectual for EV load management. TEP programming must continue to optimize EV load.[1737] Mr. Myrom also stated that EV load growth has been at or above the "500K EV" by 2030 EV scenario utilized in the 2021 Integrated Resource Plan (Case No. U-21090), annual TEP related reports, and prior electric rate cases. He noted that total EV load growth, which was what truly mattered for margin analysis and TEP program funding, remained solidly on track.[1738]

Mr. Myrom then introduced proposed TEP enhancements. First, the allowance of the weatherized and EV-rated National Electric Manufacturers Association ("NEMA") 14-50 outlets across all L2 rebate categories and NEMA 5-207 outlets across all long-duration L1 rebate categories. Second, the continuation of Direct Current Fast Charging

---

[1736] 3 Tr 1867-68.
[1737] 3 Tr 1868-69.
[1738] 3 Tr 1869-70; Exhibit A-165.

("DCFC") rebates on a time-limited and selective basis, modifying the Company's fast-charging rebate proposal as follows:

a. The Company proposed a fast-charging rebate of up to $50,000 per 150 kW DCFC port. The DCFC rebates would only be available for communities that did not have at least four 150 kW DCFC ports across two or more different host sites.

b. The DCFC rebate application would only be available for two years after approval by the Commission.

c. The Company would review rebates as they were received, thereby encouraging expedited development of the skeleton network, but retaining the right to reject applications that did not offer quality customer experience.[1739]

Mr. Myrom then presented the Company's proposed criteria to guide DCFC rebate host site selection and aid EV adoption by improving the customer experience:

1. The host site should offer 24-7 charging and amenities, such as restrooms, snacks, and meal opportunities for an average dwell time of approximately 30 minutes.

2. The host site should install the fast chargers within view of the road and with pricing signage.

3. The host site should utilize fast charging dispensers that could be activated with a credit card or phone tap to pay instead of a specific app.

4. The host site must have adequate security lighting and preferably a canopy to protect customers from the weather.

5. The host site should use traffic flow designs to accommodate the multiple charge port locations of various EV models, larger EVs, and EVs pulling trailers.

6. All host sites must offer at least two 150 kW DCFC ports, and preference would be given to sites with more fast-charging infrastructure, to increase charging confidence by EV drivers. However, no more than four rebates would be offered per host-site in any case.[1740]

[1739] 3 Tr 1871.
[1740] 3 Tr 1872-73.

Mr. Myrom noted that while many TEP programs focused on relatively low-power and longer-duration charging to minimize grid impacts, and were successfully optimizing the load from those participants, the Company anticipated that new service requests for DCFCs, both public and for fleets, would grow dramatically in larger population centers. Therefore, Mr. Myrom supported the Company request to proactively prepare for new and expanded DCFC and larger fleet locations.[1741] He noted that many utilities reported that transformers supporting larger load sites (i.e., 500 kVA 3 and greater) could have lead times of 18 to 24 months or longer, which meant that waiting until a request for new or modified service for a fast-charging site or new fleet depot to place an order for these transformers and related equipment would bottleneck EV adoption.[1742] Customers preferred to choose a fast-charging destination with multiple chargers and higher power outputs to avoid the risk of queuing or impacts from a plug being down for maintenance. The Company projected that approximately 1,400 to 1,700 EV service requests of 1 MW or greater could occur by 2030. With the two-year timeframe to design a new service, procure and install make-ready equipment, and energize a site, Mr. Myrom asserted that it was prudent to act now in preparation for forthcoming EV service requests.[1743]

Mr. Myrom testified that the Company filed its 2025 TEP Annual Progress report in Docket No. U-21538 on June 27, 2025.[1744]

Staff witness Freeman assessed the Company's EV rate case proposals. He testified that Staff recommended, in addition to the updated filing requirements from Case No. U-21492, the next TEP include discussion of the impact of the recent

[1741] 3 Tr 1873.
[1742] 3 Tr 1874.
[1743] 3 Tr 1874-75.
[1744] 3 Tr 1875; Exhibit A-230.

elimination of the energy tax credits introduced and expanded by the Inflation Reduction Act of 2022, which ended September 30, 2025.[1745] Mr. Freeman noted that given this legislation was only approximately three months old, it was unclear the magnitude of this impact. In both its next TEP and rate case, Mr. Freeman expected to see a thorough discussion of these developments and how EV adoption and load would be impacted.[1746] Mr. Freeman testified that Staff supported the Company's proposal to use weatherized and EV-rated National Electric Manufacturers Association ("NEMA") 14-50 outlets across all Level 2 rebate categories and NEMA 5-20 outlets across all duration Level 1 rebate categories. Mr. Freeman considered reducing EV infrastructure costs an excellent rationale and increased utilization of multifamily charger locations was also a worthwhile goal.[1747] He also noted Staff's concurrence with the Company proposed alterations to its Direct Current Fast Charging ("DCFC") rebates on a time-limited and selective basis.[1748] The Company's alterations were consistent with Staff's prior positions that DCFC incentives should work to create a skeleton charger network and not become a permanent program. These enhancements would steer DCFC rebates towards current charging deserts and avoid subsidizing in areas with existing DCFC infrastructure.[1749]

In response to MNSC witness Jester's proposed changes to the DCFC rebate program, Mr. Freeman expressed openness on the part of Staff to applicants being able to request variable rebate amounts – with the federal landscape shifting dramatically,

---

[1745] 6 Tr 4250-51.
[1746] 6 Tr 4251.
[1747] 6 Tr 4252.
[1748] 6 Tr 4252.
[1749] 6 Tr 4253.

the Company has flexibility to determine what amounts may allow for better utilization of the rebate budget. However, Mr. Freeman asserted that the overall DCFC rebate budget should remain unaltered.[1750] He stated that increasing the budget at this time would make the future evaluation of this program and the Company's transportation electrification program more difficult.[1751] As to MNSC's second recommendation of extending the rebate availability to seven years, Mr. Freeman testified on rebuttal that Staff did not support it at this time, but recommended it be raised in the Company's next rate case. Doing so would allow the Company to present the financial and programmatic impacts of a seven-year rebate window in detail and allow a fuller vetting of the proposal by both the Company and intervenors.[1752]

Ms. Schuster testified on behalf of MEIU regarding the TEP program enhancements.[1753] After reiterating the Company's TEP history and the proposed enhancements to the TEP program, Ms. Schuster focused first on the proposed modifications to its L2 and L1 rebate programs.[1754] Ms. Schuster stated that MEIU did not agree entirely with the Company's proposed modifications. She noted that while the recommendation would allow flexibility in the program to suit the customer's specific needs and reduce the customer's make-ready costs, it was unclear how the Company planned to ensure that a customer with a NEMA 14-50 or 5-20 outlet would actually purchase the charger and participate in the TOU rate or any future managed charging

[1750] 6 Tr 4255.
[1751] 6 Tr 4255-56.
[1752] 6 Tr 4255-56.
[1753] 6 Tr 4162.
[1754] 6 Tr 4162-67.

program.[1755] Therefore, Ms. Schuster stated that MEIU recommended the Commission require the Company to ensure that if a customer chooses to install a NEMA 14-50 outlet, that they also purchase or obtain an EV charger or charging cord and provide proof of EV purchase or lease.[1756]

Ms. Schuster then asserted that the Company's consideration of the 30C Vehicle Refueling Property Tax Credit should not be factored into evaluation of the impact of the DCFC rebate on DCFC installation costs for public site hosts because it will sunset on June 30, 2026.[1757] Ms. Schuster further noted that the Company did not explain how it would determine the rebate amount an applicant would be eligible to receive based on whether the site design meets the other optional criteria.[1758]

Ms. Schuster did not entirely agree with the Company's proposed modifications to its DCFC rebate program. She stated that the Company's proposed required criteria (i.e., security lighting and minimum number of ports) were reasonable, and the Commission should approve those modifications to the DCFC rebate program. However, she had concerns with some of the Company's proposed optional criteria for its DCFC rebate program. Specifically, as to the rebate amount, she recommended that to prepare for the loss of the 30C tax credit at the end of 2026 and to ensure that the DCFC program was as effective and impactful as possible, the Commission should direct the Company to increase the DCFC rebate amount to up to $70,000 per port. Then as to time limitation, Ms. Schuster stated MEIU recommended that the

[1755] 6 Tr 4167.
[1756] 6 Tr 4168.
[1757] 6 Tr 4168.
[1758] 6 Tr 4169.

Commission reject the Company's proposed DCFC program two-year time limitation.[1759] Next, she asserted that while the rationale to prioritize DCFC rebates to communities that do not yet have adequate DCFC infrastructure was sound, the description of what the Company means by "community" or "traditional government boundary" in order to determine whether a site could be considered eligible for the rebate program was vague. As such, the Commission should require the Company to clearly define "community" in its DCFC rebate program application guidelines.[1760] Finally, Ms. Schuster testified that the optional criteria, and the way the Company proposed to evaluate and compare applications, lacked clarity. Therefore, she recommended that the Company establish designated amounts or weighted amounts associated with each project criterion and develop a publicly available rubric by which it would score DCFC project applications. This could be based on evenly distributed weights or dollar amounts, or the Company could designate certain criteria as more important and therefore worthy of greater weight or a higher dollar amount.[1761] The Company stated its intent to review and award DCFC rebate applications monthly. Ms. Schuster asserted that this leaves the evaluation process vulnerable to subjectivity in the review process from one month to the next, which could make the review process more contentious as the Company continued to issue rebates and spend program funds. Creating a rubric, as described above, would make it easier for the Company to objectively review each

[1759] 6 Tr 4170-71.
[1760] 6 Tr 4171-72; Exhibit Meiu-1.4.
[1761] 6 Tr 4172.

application, ensuring that the process remains consistent throughout the duration of the program.[1762]

Mr. Jester provided MNSC's review of the Company's proposed TEP enhancements.[1763] Mr. Jester noted that the Company proposed two main enhancements – expanded outlet eligibility for rebates and continuation of DC Fast Charging Rebates.[1764] Mr. Jester expressed support for the proposal to expand outlet eligibility for rebates noting that it would reduce costs for multifamily customers and expand charging access without compromising charging quality. However, he noted that MNSC did not support the proposal to continue DC Fast Charging Rebates as presented.[1765] Due to the elimination of the 30C tax credit, a higher incentive would be required for many site hosts to justify the investment. Rather than asking the Company to simply increase its rebate level, the Company could instead revise its application process to allow applicants to request a specific rebate amount based on their project circumstances. The Company would then continue to select the most competitive applications, but competitiveness would now be assessed in part by the rebate amount requested. Mr. Jester also stated the Company should extend its DCFC rebate program to remain available for seven years instead of two to match the original expiration timeline of the 30C tax credit.[1766]

As to the pace and distribution of rebates, Mr. Jester also expressed concern regarding the relatively small number of multifamily rebates issued to date, given the

---

[1762] 6 Tr 4173.
[1763] 6 TR 3999-4008.
[1764] 6 Tr 4001-02.
[1765] 6 Tr 4002.
[1766] 6 Tr 4002-03.

importance of this customer segment for equitable access to EV charging. According to him, Multifamily properties face unique barriers, such as shared parking and cost allocation between landlords and tenants, that required more focus than was evident from the number of rebates issued.[1767] The Company's proposal to expand outlet eligibility to better attract multifamily site hosts was a step in the right direction. Recognizing the need to expand access in this segment, the Company should strengthen its efforts by dedicating resources to targeted outreach and education aimed specifically at multifamily dwellings.[1768]

Mr. Jester next noted that the Company's reported success in shifting the vast majority of L1 and L2 charging to off-peak hours was achieved primarily through time-of-use rates, customer education, and incentive payments.[1769] Mr. Jester noted that the Company's own forecasts showed that overall EV load growth was expected to outpace the growth of TEP-managed EV load between now and 2030. He asserted that this imbalance raised two concerns. First, the Company's managed charging strategy and the resulting grid and ratepayer benefits may soon be overwhelmed by the scale of unmanaged EV load growth, highlighting an urgent need to scale enrollments in TEP programs. Second, the average future EV driver could not be assumed to behave like the early adopters who have participated to date. Incentives and education alone may not be enough to influence charging behavior at scale. For this reason, Mr. Jester asserted on behalf of MNSC that active managed charging and V2X capabilities should be integrated into the TEP now, rather than deferred until 2028, to ensure proven tools

[1767] 6 Tr 4003; Exhibits CUB-13, CUB-16.
[1768] 6 Tr 4004.
[1769] 6 Tr 4004.

were in place before unmanaged load growth overwhelms the current passive approach.[1770]

In response to Mr. Freeman, Mr. Myrom noted that the loss of the EV tax credit, in addition to other potential tax impacts from Federal initiatives like tariffs would 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 anticipates that this pull-forward could result in a temporary reduction in EV adoption in Q4 of 2025, but by mid-2026 he anticipates a trend toward normalization of customer behavior, barring further regulatory developments. The Company would continue to reforecast EV adoption in the annual reports and TEP filings going forward.[1771] Mr. Myrom agreed with Staff's support for the use of weatherized EV-rated outlets across all rebate categories and for a temporary Direct Current Fast Charger ("DCFC") rebate program for underserved communities, noting that the Company served many smaller communities, especially in the northern half of the lower peninsula, that experienced seasonal and weekend travel patterns related to Michigan's fantastic tourist destinations, which would benefit from fast charging infrastructure.[1772]

In response to Ms. Schuster's recommendation that rebate recipients utilizing the proposed outlet option provide proof of EV purchase or lease, Mr. Myrom disagreed, in part. He noted that he proposed expanding the option to use "NEMA 14-50 or NEMA 5-20 outlets from community charging applicants to applicants for multifamily charging,

---

[1770] 6 Tr 4005.
[1771] 3 Tr 1878.
[1772] 3 Tr 1879.

workplace charging, and fleet charging. In the community charging scenario, for which BYOC was already approved, no proof of EV purchase or lease was required because the charging infrastructure was open to the public. The Company asserted that it would be impractical to verify or mandate EV adoption for Level 2 rebates for multifamily and workplace charging; however, for fleet charging the Company has and would continue to require proof of EV adoption (purchase or lease) to qualify for a rebate.[1773] Therefore, the Company agreed that fleet charging required proof of EV adoption but disagreed that proof was needed for multifamily and workplace charging given the characteristics of those EV charging host sites.[1774]

In response to Ms. Schuster's recommendation that the fast-charging rebate be increased to $70,000 and the two-year application window be extended to six years, Mr. Myrom noted that the Company's long-term TEP strategy remained centered on lower-power, longer-duration, off-peak charging infrastructure to optimize the grid. Nonetheless, if the fast-charging proposal proved insufficient to achieve the skeleton network outcome, then the Company was very willing to consider higher rebate values and a longer application window duration in a future filing.[1775] In response to MEIU's recommendation that the Company provide an explicit definition of "community" and a clear rubric for fast-charger rebate applicant review, Mr. Myrom noted that the Company defined community as a governmental boundary and referred to his direct testimony regarding the criteria for rebate selection.[1776]

[1773] 3 Tr 1880-81.
[1774] 3 Tr 1881.
[1775] 3 Tr 1881-82.
[1776] 3 Tr 1882; Exhibits A-223, A-224.

In response to Mr. Jester's recommendation that the fast-charging rebate application window be extended to seven years given the Federal tax credit recission, Mr. Myrom noted that, if proven necessary with time and market development, such changes could and would be proposed in future rate cases.[1777] Mr. Jester also recommended that the Company allocate specific funding for education and outreach to multifamily dwellings, to which Mr. Myrom testified that targeted outreach and rebates to address multifamily charging would continue to be a focus in the Company's 2026 TEP.[1778]

Mr. Jester further recommended several things to which the Company did not agree. First, that the Company propose an active managed charging and telematics pilot in the next rate case, in response to which the Company acknowledged that telematics and active managed charging remained potential future elements of the Company's TEP. However, the Company wanted significant confidence in long-term solutions that had minimal risks and costs, and solutions which cover the majority of EVs in the Company's electric territory before committing to a pilot in the next rate case.[1779] Second, that the Company again propose a battery-integrated DCFC pilot in the next rate case; however, the Company utilized the guidance and feedback in Staff testimony and proposed the limited-time DCFC rebate program instead.[1780] And lastly, that the Company expand PowerMIFleet with a V2G-enabled electric school bus pilot in the next rate case. In response, the Company witness Myrom acknowledged that bidirectional charging remained a potential future element of the Company's TEP but

[1777] 3 Tr 1882.
[1778] 3 Tr 1883.
[1779] 3 Tr 1883-84.
[1780] 3 Tr 1884.

stated that it did not believe that there were unique aspects of bidirectional charging technology specific to its territory that needed to be explored through a pilot at this time.[1781]

In its brief, the Company reiterates Mr. Myrom's testimony regarding the proposed two enhancements to the TEPs.[1782] The Company notes that other parties largely supported the Company's program and its enhancements, though some had further recommendations – one of which the Company supports.[1783] Mr. Freeman recommended that the Company consider, in its upcoming TEP in 2026, the impact that the federal EV tax credit sunset will have on the Company's forecasted EV growth and the Company will continue to re-evaluate its forecasts in annual reports and TEP filings going forward.[1784] The Company is not yet ready to propose a new fast-charging tariff in the next rate case, the data set is not yet sufficient to propose a new rate structure.[1785] The Company recommends that the Commission reject MEIU's recommendation to increase the fast-charging rebate at this time, as well as the various recommendations from MNSC.[1786]

In its brief, Staff also reiterates the testimony on TEP enhancements and recommendations.[1787] Staff notes the Company agrees to Staff's recommendation to

---

[1781] 3 Tr 1885.
[1782] Company brief, pp. 176-77.
[1783] Company brief, p. 178.
[1784] Company brief, pp. 178-79.
[1785] Company brief, p. 179.
[1786] Company brief, p. 180-82.
[1787] Staff brief, pp. 188-89.

address the impact of changes to federal law on EV registrations and EV adoption in its upcoming TEP.[1788] Staff supports the Company's proposed changes to the TEP.[1789]

In its brief, MNSC reiterates its support for the Company's enhancements to the TEP with its recommended modifications.[1790] MNSC also recommends the Commission require the Company to propose a set of pilots that begin integrating more active load-management tools into its TEP.[1791]

In its brief, MEIU reiterates Ms. Schuster's testimony and states that MEIU supports the Company's proposed "enhancements," subject to the MEIU recommended modifications.[1792]

Having reviewed the testimony and recommendations regarding the Company's proposed TEP enhancements, this PFD recommends the Commission approve the Company's proposed enhancements for the reasons discussed above.

As to Staff's recommendation that the Company consider the impact that the federal EV tax credit sunset will have on the Company's forecasted EV growth, the Company agreed in its brief to continue to re-evaluate its forecasts in annual reports and TEP filings going forward. This recommendation is reasonable, and this PFD recommends that this direction be included in the Commission's order. The Company also agreed that fleet charging required proof of EV adoption but disagreed that proof was needed for multifamily and workplace charging given the characteristics of those EV charging host sites, therefore, this PFD recommends the Commission order note

---

[1788] Staff brief, p. 188.
[1789] Staff brief, p. 188-89.
[1790] MNSC brief, pp. 22-23.
[1791] MNSC brief, p. 26-29.
[1792] MEIU brief, pp. 4-5.

that the Company agreed that fleet charging required proof of EV adoption. And it agreed that targeted outreach and rebates to address multifamily charging would continue to be a focus in the Company's 2026 TEP, which this PFD also recommends the Commission order note.

As to MEIU's recommendation that the Company be required to explicitly define "community" for rebate eligibility, this PFD concurs that Mr. Myrom's definition leaves applicants in the dark as to the area they need to evaluate when consideration an application for rebate and therefore, this PFD recommends the Commission direct the Company to clearly state which "traditional government boundary" it considers a "community" for the purpose of rebate eligibility. Additionally, this PFD finds it reasonable for applicants to know how their application for rebate will be evaluated, therefore, this PFD recommends the Commission direct the Company to publish a clear rubric and methodology that will govern its application evaluation. As to the MEIU and MNSC recommendations to raise the rebate values and lengthen the application window, this PFD recommends that the Commission not adopt them in this rate case.

In its brief, Staff asserts that rebates are available for DCFC to address the capital expense and help with the return of investment.[1793] Staff pushes back on Ms. Schuster's suggestion that there is no subsidy for EV charging stations on Rate GP when considered in the aggregate, stating that this is "akin to saying industries hire people that are residential customers, therefore low industrial rates help utilities because more residential customers pay rates that lead to increased revenue in the

[1793] Staff initial brief, p. 158.

aggregate."[1794] Staff argues that this line of thought should be rejected and each class should be evaluated on its own merit, which means evaluating DC fast charging separately from at home charging.[1795] Staff also argues that if other states are examined for EV rate best practices, only those that have cost of service requirements like Michigan, should be considered. [1796]

MEIU's brief largely tracks Ms. Schuster's testimony.

11. Accumulated Provision for Depreciation

In Consumers' original filing the accumulated provision for depreciation for the projected test year was $6,650,643,000.[1797] Staff witness Witt presented Staff's depreciation reserve of $6,644,587,000, which is a reduction of $6,056,000, based on Staff's adjustments to the Company's historic and projected capital expenditures.[1798]

In rebuttal, Consumers adjusted the accumulated provision for depreciation based on facts and circumstances revealed after the filing of its case.[1799] The amount of $250,023 was also removed based on Consumers' agreement to remove ARP-Collaboration capital expenditures for 2025.[1800] Consumers recommends that the Commission approve the depreciation reserve amount of $6,649,488,000.[1801]

The accumulated provision for depreciation should be adjusted based on the Commission's final order in this case.

[1794] Id.
[1795] Id.
[1796] Id., p. 159.
[1797] Consumers initial brief, p. 182; Ex. A-12, Sch. B-3.
[1798] 6 Tr 4604; Exhibit S-2, Schedule B-1.
[1799] 3 Tr 1088.
[1800] Consumers initial brief, p. 183, App. B1.
[1801] Consumers initial brief, p. 183.

B. Working Capital

Mr. Daly presented Consumers' projected test year balance sheet working capital requirement of $2,125,887,000.[1802] He testified that the Company determined the working capital requirement using the balance sheet approach, which was required by the Commission in Case Nos. U-7350 and U-15895.[1803]

The Attorney General disagrees with Consumers proposed working capital requirement. Specifically, Mr. Coppola recommended three adjustments to working capital for the projected test year: 1) a reduction of Consumers' forecasted test-year cash level by $41.4 million; 2) a reduction of $30.0 million based on an adjustment to the Company's accrued tax; and 3) a reduction of $2.6 million for cloud computing deferred costs for the SAP S/4 HANA project.[1804] These changes total $74.0 million and would reduce the amount of Working Capital amount from $2.126 billion to $2.052 billion.[1805] These issues are addressed below.

1. Cash Balance

Mr. Bleckman testified that the historical cash balance of $36.4 is lower than expected for the test year, and he recommended that the Consumers' projected cash balance should equate to approximately 1% of test year electric revenues, which results in a cash balance of $50.4 million.[1806] Mr. Bleckman offered several factors supporting a cash balance of $50.4 million and the 1% rule of thumb method. First, he testified that while there are myriad factors that affect cash balances at any point in time, including

---

[1802] 3 Tr 1054; Ex. A-12, Sch. B-4.
[1803] 3 Tr 1054.
[1804] 3 Tr 2506-2507; Ex. AG-33.
[18051805] 3 Tr 2506.
[1806] 3 Tr 843.

weather, storm costs, and gas prices, Consumers has consistently used the 1% rule of thumb method to project cash balances.[1807] Second, he asserted that the method minimizes liquidity risks. He testified that having adequate cash on hand reduces Consumers' extended reliance on short-term borrowing facilities, which can be volatile and, at times, unavailable, and helps the Company secure the lowest interest rate on its long-term debt.[1808] He asserted that maintaining a ratio of 1% cash balance to revenue helps maintain an overall liquidity that is sufficient to carry out day-to-day operations but is flexible enough to meet investing activities should there be a delay in accessing long-term capital from capital markets.[1809] Next, Mr. Bleckman maintained that from 2016 to 2024, the ratio of Consumers' cash balances compared to operating revenues approximated 1%, except for: 2020 during the pandemic; 2022 when gas prices spiked; and 2023 due to weather and storm restoration activity.[1810] He presented a chart which appears to show that: in 2016 and 2024, the ratio was less than 1%, but greater than 0.5%; in 2018 and 2021, the ratio was nearly 1%; in 2017, the ratio was greater than 1%, but less than 2%; and in 2019, the ratio was slightly more than 1%.[1811] And he testified that for the years in which Consumers' cash balances were unusually higher or lower than normally expected, the Company adjusted its rate case projected cash balance to account for these deviations.[1812] Lastly, Mr. Bleckman maintained that Consumers' cash balance impacts its credit rating. He explained that the three major credit reporting agencies, S&P, Moody's, and Fitch, consider the level of cash on hand

---

[1807] 3 Tr 844, referring to Case Nos. U-21148 and U-20963.
[1808] 3 Tr 845.
[1809] 3 Tr 845-846.
[1810] 3 Tr 846-847.
[1811] 3 Tr 846.
[1812] 3 Tr 847.

to be an important component of their assessment of Consumers' credit quality and credit rating.[1813]

Mr. Coppola recommended that the projected test year cash balance of $50.4 million be reduced by $41.4 million to $9.0 million, as it more accurately reflects Consumers' operational cash needs. He testified that Consumers' proposal to increase its average cash balance based on the 1% rule of thumb is problematic and unsupported.[1814]

Mr. Coppola detailed five problems with Consumers' approach. First, he maintained that sizable amounts of existing cash end up in short-term investments bearing interest that "pad the Company's bottom line."[1815] Second, he asserted that there is no logical connection between revenues and the need for cash on hand. He explained that cash on hand is not used for revenues, it is used to pay operating expenses, capital expenditures, and dividends to the parent company.[1816] Third, he maintained that utilities keep different levels of cash on hand during different months of the year depending on their seasonal needs for cash to pay for operating expenses and construction costs.[1817] Fourth, he testified that using an average ratio of cash on hand to revenues at a specific point in time does not take into consideration the unique aspects of a particular utility since each utility has different short-term borrowing facilities and different practices as to how to use them.[1818] Fifth, Mr. Coppola opined that Consumers' method is likely inflated and inappropriate because the Company arrived at the 1% ratio

---

[1813] 3 Tr 847-848.
[1814] 3 Tr 2507.
[1815] Id.
[1816] 3 Tr 2508.
[1817] Id.
[1818] Id.

using other utilities' reported cash balances, which included cash invested in short-term securities under generally accepted accounting practices (GAAP). He maintained that the Commission does not allow those short-term cash investments with interest bearing securities in the calculation of cash on hand for inclusion in working capital.[1819]

Mr. Coppola questioned Mr. Bleckman's assertion that the Commission reconfirmed the use of the 1% ratio in Case No. U-21389. He stated that the Commission's order in that case shows that it is not wedded to the approach.[1820] He also asserted that in Case U-21585, based on evidence he provided, the Commission made it clear that a different approach may be warranted in future cases.[1821]

Mr. Coppola testified that he used Consumers' average cash balance from the past three years, 2022-2024, to obtain a normalized average of the Company's cash needs, which is $25.1 million ($25.3 million lower than Consumers' forecast).[1822] He noted that since the $25.1 million includes an average level of cash invested in interest bearing securities of $16.1 million, he removed this amount. As a result, he contended, the net cash required to operate Consumers' electric business is approximately $9.0 million.[1823]

Mr. Coppola testified further that setting a higher cash balance in working capital significantly benefits Consumers but comes at a cost to customers. He explained that having a higher cash balance increases the rate base and therefore Consumers' rates, and the Company earns additional money by investing the extra cash in short-term

---

[1819] Id.
[1820] 3 Tr 2508-2509, citing Case No. U-21389, Order, March 1, 2024.
[1821] 3 Tr 2509, citing Case No. U-21585, Order, March 21, 2025, p. 213.
[1822] 3 Tr 2509-2510; Ex. AG-34.
[1823] 3 Tr 2510.

securities.[1824] He added that contrary to Mr. Bleckman's assertion, cash on hand does not solve liquidity problems. He opined that access to short-term credit facilities is key to solving large cash needs and Consumers can resolve smaller liquidity issues by drawing on bank lines or issuing commercial paper.[1825]

In rebuttal, Mr. Bleckman stated that he provided extensive evidence in his direct testimony that a $50.4 cash balance, or 1% of electric revenues, is a level that is needed, reasonable, balanced, and minimizes Consumers' financial and credit risk.[1826] He maintained that it is not based on projections of future cash outflows, as Mr. Coppola suggested, instead it is "a simple, efficient, and easily calculated benchmark that is useful in estimating a reasonable level of cash for the Company."[1827] He testified further that the 1% rule of thumb is not intended to match other utilities' liquidity and financing practices, but it is what is reasonable and appropriate for Consumers.[1828] As for the use of GAAP data in the analysis, Mr. Bleckman noted that Mr. Coppola performed analyses based on GAAP financial data in his testimony regarding Moody's FFO-to-Debt ratio and the peer group equity ratio.[1829]

He testified that the Commission approved Consumers' projected cash balances calculated using the 1% rule of thumb in its two most recent electric cases, Case No. U-21389 and U-21585, and in its most recent gas case, Case No. U-21806.[1830] And he added that in Case No. U-21585, the Commission found Consumers' projected cash

---

[1824] 3 Tr 2510-2511.
[1825] 3 Tr 2511-2512.
[1826] 3 Tr 915.
[1827] Id.
[1828] 3 Tr 916.
[1829] 3 Tr 916-917, citing AG-44 and AG-38.
[1830] 3 Tr 917.

balance to be “reasonable and prudent” and instructed the Company 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.”[1831] He asserted that his direct testimony satisfied this requirement, and he noted that the Commission rejected Mr. Coppola’s proposed cash balance disallowance in prior rate cases.[1832]

Mr. Bleckman maintained that using the average of actual cash balances from 2022, 2023, and 2024, as proposed by Mr. Coppola, results in a cash balance much lower than is normally expected. He testified that the cash balances from 2022 and 2023 were abnormally low and atypical due to gas price spikes and weather, respectively.[1833] Also, he stated, Consumers uses a forward-looking test year and basing the projected cash balance on current or historical revenues is not appropriate.[1834]

As for Mr. Coppola’s recommendation to remove $16.1 million to account for cash invested in interest bearing securities, Mr. Bleckman contended it should be rejected. According to Mr. Bleckman, while the $16.1 million is included in interest bearing operating cash accounts, these are not restricted cash investments and are available for Consumers to draw on at any time.[1835] He maintained that the cash accounts Mr. Coppola wants to remove are properly included in working capital consistent with long-standing ratemaking practice, and Consumers does not include any

---

[1831] Id.; Case No. U-21585, Order, March 21, 2025, p. 213.
[1832] 3 Tr 917-918.
[1833] 3 Tr 918.
[1834] Id.
[1835] 3 Tr 919.

restricted cash investments in its cash balance calculation.[1836] Mr. Bleckman added that any interest earned on rate base working capital cash balances is included as a reduction to the revenue requirement.[1837]

Lastly, Mr. Bleckman contended that it is not prudent to maintain a low cash balance and rely on short-term credit facilities to solve liquidity challenges that may arise, and a cash balance of $9.0 million, or 0.2% of test year revenues, is extremely low given the size of the Consumers' business and its operating cash flows.[1838] He opined that Mr. Coppola's recommendation to carry a low cash balance and rely on short-term debt is detrimental to the Company's credit quality and is punitive and unsupported.[1839]

Mr. Daly also provided rebuttal testimony and echoed Mr. Bleckman's contentions about the appropriateness of holding cash in interest-bearing accounts. According to Mr. Daly it would be improper to exclude these accounts from the working capital calculation.[1840] He maintained that if the Commission rejects the 1% of revenue approach, then the appropriate cash balance should be the historical 13-month average of $36.4 million, which has been long-standing practice by Consumers and accepted by the Commission, and not the three-year average balance as proposed by Mr. Coppola.[1841]

Consumers' briefing repeats Mr. Bleckman's and Mr. Daly's testimony and supports a cash balance of $50.4 million, or 1% of revenues. Consumers urges the

---

[1836] Id.
[1837] Id.
[1838] 3 Tr 920.
[1839] 3 Tr 920-921.
[1840] 3 Tr 1087; Ex. A-13.
[1841] 3 Tr 1088; Ex. A-12.

Commission to reject Mr. Coppola's proposed "unreasonably low" $9 million cash balance.[1842]

The Attorney General's briefing generally repeats Mr. Coppola's testimony and argues that Consumers has a history of over projecting its cash needs to the detriment of ratepayers.[1843] She maintains that the net cash required to operate Consumers' electric business is approximately $9.0 million.[1844] She counters Mr. Bleckman's claims that the 1% of test year revenue rule of thumb is not intended to match other utilities liquidity and financing practices, stating that Consumers cannot explain why using the 1% revenue rule of thumb is a better approach than using the Company's own average cash balance as recommended by Mr. Coppola.[1845]

Consumers does not address the cash balance in its reply, while the Attorney General rejoins issues raised in Consumers' initial brief. In response to Consumers' argument that its proposed cash balance reflects a normal level of cash needed to manage working capital requirements and financial risk, she responds that, "[i]t may be normal in the sense that the Company consistently uses its illogical methodology to project a cash balance, however the methodology results in an inflated cash balance that far exceeds its cash needs."[1846] As for the propriety of using short-term debt for cash needs that may arise, she argues that Consumers already has a layer of short-term debt in place which provides more than enough liquidity for its utility operations.[1847] Noting S&P's, Moody's and Fitch's assessments of Consumers' liquidity, she argues

---

[1842] Consumers initial brief, p. 184-188.
[1843] AG initial brief, p. 109-110.
[1844] Id., p. 114.
[1845] Id., p. 114-115.
[1846] AG reply brief, p. 9-10.
[1847] Id., p. 10.

that all three credit agencies agree with her that Consumers has more than enough liquidity from its short-term borrowing facilities and does not require a $50.4 million cash balance.[1848] She contends that her recommendation to remove $16.1 million from interest bearing accounts is reasonable even if these accounts are not considered "investments," as Consumers "is earning something on the account" and the money is available to the Company "at any time."[1849] And she argues, even if interest on the account is included as a reduction to Consumers' revenue requirement, once it is included in rate base, the Company will earn a return of nearly 10% on it.[1850]

The Attorney General asserts that while the Commission has previously approved Consumers' cash balances, which were calculated using the 1% revenue method, it has limited its findings to the specific case before it.[1851] And she contends, in this case, Consumers' proposed cash balance is inflated and does not reflect its actual cash needs.[1852] Lastly, she argues that the Commission should reject Consumers' alternative proposal to base the cash balance on the historical 13-month average of $36.4 million. She avers that her recommended $9.0 million cash balance meets Consumers' cash needs, but if the Commission rejects her $16.1 million adjustment, the cash balance should be no more than the three-year average of actual cash balances, which is $25.1 million.[1853]

This PFD notes that in Case No. U-21585, Consumers used the 1% of revenue method to project its proposed cash balance and the Attorney General made the same

---

[1848] Id., p. 10-12; Conf. Exs. AG-47 to AG-49.
[1849] Id., p. 12.
[1850] Id.
[1851] Id., p. 12-13, quoting Case No. U-21806, Order, Sept. 30, 2025, p. 149.
[1852] Id., p. 12-13.
[1853] Id., p. 13-14.

arguments against it, that is that Consumers' historical cash balances militated against the method and the Company can use short-term borrowing facilities to meet any unusual needs. Consumers rejoined that its projected cash balance was reflective of normal and necessary levels of cash. Both parties referred to previous Commission orders as supporting their cause. The ALJ in Case No. U-21585 agreed with the Attorney General, however, the Commission did not. The Commission was unpersuaded by the Attorney General's arguments and noted that there is no guarantee that short-term borrowing will be available when needed.[1854] The Commission emphasized that it determines the cash balance each year on a case-by-case basis.[1855] Nevertheless, the Commission found that based on Consumers' recent actual cash balances it needed a more specific explanation of why the 1% revenue method remains appropriate and should continue to be approved.[1856] In this case, Consumers and the Attorney General offered more fine-tuned arguments for or against the 1% method and again referred to prior Commission orders.

This PFD finds Consumers' presentation of the historical ratio of cash balances to revenues from 2016 to 2024 compelling and persuasive. It shows that excluding 2020 when the ratio was over 6% and 2022 and 2023 when the ratio appears to have been less than 0.5%, the ratio in all the other years, while sometimes higher or lower, is around 1%. It is also noted that in this case the Attorney General's argument that Consumers' actual cash balances were lower than the 1% ratio is based on balances from 2022-2024 and Consumers rebutted the use of 2022 and 2023 as they were

[1854] Case No. U-21585, Order, March 21, 2025, p. 213.
[1855] Id.
[1856] Id.

unusual because of gas price spikes and weather incidents. Additionally, it is noted that in Case No. U-21585, the Attorney General also focused on 2022 and 2023 cash balances and the Commission stated that it was, "unpersuaded, based on the cash balance fluctuations presented in this record, that Consumers' approach in determining its projected cash balance is necessarily wrong."[1857] This PFD also agrees with Consumers that the Attorney General's contention that it can use short-term debt to address any unusual cash needs is imprudent as it is considered in the Company's credit rating. Furthermore, as noted by Consumers and by the Commission in Case No. U-21585, there is no guarantee that short-term borrowing will be available when needed.[1858] This PFD finds that Consumers has successfully supported the use of the 1% rule of thumb in this case and the Attorney General's arguments otherwise do not change this determination. This PFD recommends approval of Consumers' proposed cash balance of $50.4 million. This PFD rejects the Attorney General's proposed $9 million cash balance as it was derived in part using historical cash balances from unusual years, 2022 and 2023. Furthermore, this PFD finds that her recommended removal of $16.1 million based on it being the average level of cash invested in interest bearing securities is not reasonable based on the Company's assertions that relevant cash accounts are not restricted, are properly included in working capital, and any interest is deducted from Consumers' revenue request.

[1857] Id.
[1858] Id.

2. Accrued Taxes

Consumers' working capital projections include a $30 million reduction to accrued taxes, resulting in test period accrued taxes of $256.080 million and an increase to working capital of $30 million.[1859]

Mr. Coppola opposed the $30 million reduction to accrued taxes. He testified that in discovery, Consumers stated that the reduction is based on its assumption that it will not receive additional income from rate relief.[1860] Mr. Coppola called this assumption unrealistic and Consumers' calculation of accrued taxes seriously flawed. He noted that in Case No. U-21585, Consumers received 51% of the amount requested or approximately $154 million annually, and while this percentage could be used to recompute accrued taxes at a higher level, a more conservative approach would be to use actual accrued taxes from the historical 2024 period.[1861] Accordingly, he recommended that the Commission use the historical balance of accrued taxes of $286.1 million for the projected test year and reduce working capital by $30.0 million.[1862]

In rebuttal, Mr. VanBlarcum testified that Consumers determined accrued taxes using the 13-month average from December 2024, which was $286,120,000, and this necessitated a downward adjustment because the amount included Federal, State, and Local income taxes accrued for the 2023 and 2024 tax years and therefore was not reflective of the projected test period May 1, 2026 through April 30, 2027.[1863] He explained that since accrued income taxes included in the December 2024, 13-month

---

[1859] Ex. A-12, Sch. B-4.
[1860] 3 Tr 2512.
[1861] 3 Tr 2512-2513.
[1862] 3 Tr 2513.
[1863] 3 Tr 2268-2269; Ex. A-12, Sch. B-4.

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.[1864] He explained further that accrued taxes are calculated on taxable income derived from both pre-tax book income and timing differences that generate deferred income taxes, and deferred income taxes are a zero-cost component of the capital structure. He maintained that ratemaking principles and IRS requirements support the $30 million reduction.[1865] He stated:

> 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.[1866]

He contended that Consumers' adjustment to accrued taxes ensures compliance with the Internal Revenue Code, while Mr. Coppola's recommendation would create discordance between Consumers' capital structure and rate base.[1867]

As for Mr. Coppola's assertion that Consumers acknowledged that accrued taxes for the test year do not include additional income from the rate relief requested in this case, Mr. VanBlarcum maintained that Consumers calculated an appropriate amount of

---

[1864] 3 Tr 2269.
[1865] Id.
[1866] 3 Tr 2269-2270.
[1867] 3 Tr 2270-2271, citing §168(i)(9)(B) of the Internal Revenue Code.

accrued taxes based on Federal, State, and Local taxable income projections relative to the projected test year.[1868] And he contended that Mr. 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. He emphasized that "no other working capital items are adjusted to reflect requested rate relief."[1869]

In its brief, Consumers repeats and elaborates on Mr. VanBlarcum's testimony, while the Attorney General's brief relies on Mr. Coppola's testimony and responds to Mr. VanBlarcum's rebuttal testimony. She remarks that it seems inconsistent not to include additional income from rate relief requested in this case in the accrued taxes for the test year.[1870] She also notes that while Consumers refers to the section of the Internal Revenue Code addressing the treatment of adjustments, which use estimates or projections with some exceptions, the Company included income tax liability for the projected test year in this case.[1871] Additionally, she argues there is no mention or prohibition in the IRS rules for the calculation of accrued taxes through the end of the projected test year that would take into account the additional income taxes that Consumers will need to pay from the additional income generated from the rate increase.[1872] She points out that there is a disconnect in Consumers' practice because it calculates income tax expense for the proposed rate increase but does not recognize

[1868] 3 Tr 2271; Ex. A-228 and Ex. A-229.
[1869] 3 Tr 2272.
[1870] AG initial brief, p. 115-116; Ex. AG-80.
[1871] AG initial brief, p. 116; Ex. AG-78.
[1872] AG initial brief p. 116-117.

that the tax expense will result in the payment of accrued taxes during the projected test year.[1873]

This PFD declines to adopt the Attorney General's proposed adjustment to accrued taxes and the resulting reduction of $30 million to working capital. This PFD finds that the Attorney General's recommendation is based on her perceived inconsistent treatment of taxes related to any additional income from the rate relief requested in this case. However, this PFD finds that Consumers sufficiently explained why its $30 million adjustment was necessary and in accordance with ratemaking principles and IRS rules.

3. Cloud Computing Deferred Costs

Mr. Coppola recommended the removal of $2.576 million from working capital associated with the deferral of the cloud computing costs for the SAP S/4 HANA project.[1874] Consistent with his testimony on the capital expenditures and deferred accounting requests associated with the project, Mr. Coppola opined that the project was premature and should be rejected. Accordingly, he removed the cloud computing costs for the SAP S/4 HANA project from the test year working capital.[1875] The Attorney General's brief also notes that Consumers admitted that it did not have a contract in place for the SaaA solution that would support the cloud computing costs.[1876]

Consumers argues that the SAP S/4 HANA project is not premature and that Mr. Coppola's recommendation to remove $2.576 million from working capital should be rejected. The Company maintains that approving the deferral of O&M expenses, and

[1873] Id., p. 117.
[1874] 3 Tr 2513.
[1875] Id.
[1876] AG initial brief, p. 118.

amortizing cloud implementation costs over 15 years, will align the cost recovery with the period over which the project delivers benefits and help mitigate customer rate impact.[1877]

For the reasons explained in the IT Capital Expenditures Section, this PFD rejects the Attorney General's recommended removal of $2.576 million from working capital.

C. Total Rate Base

Consumers calculated its total rate base for the projected test year of $15,330,175,000.[1878] Staff recommends a total rate base of $15,208,892,000, a difference of $121,283,000, corresponding to several proposed reductions to Consumers' capital expenditures, including projected distribution, generation, information technology, and operations support, and adjusted by reduced depreciation reserve.[1879] The Attorney General recommends a reduction in rate base of $642.5 million based on capital expenditure reductions.[1880]

Please see the PFD appendices, which will be available on the docket on or before February 6, 2026, for the PFD's final adjustments and projected total rate base.

V.

CAPITAL STRUCTURE AND RATE OF RETURN

The capital structure used for ratemaking includes as its components long-term debt, preferred stock, and common equity capital – which are considered part of the

[1877] Consumers initial brief, p. 190.
[1878] Consumers initial brief, p. 191, App. B-1; Ex. A-209.
[1879] Staff initial brief, p. 1, App. E.
[1880] AG initial brief, p. 118.

utility's "permanent capital" – and includes short-term debt and other items (such as deferred taxes) that reflect sources of financing available to the company.

The rate of return used to set rates is based on the weighted average costs of the sources of capital comprising the capital structure. The weighted cost for each component of the capital structure is determined by multiplying the percentage ratio for that component by the cost rate for the component. The weighted cost rates for each component are then added to determine the overall rate of return.

In this case, Consumers seeks an overall return of 6.30% on an after-tax basis to set rates.[1881] Staff and the Attorney General recommend an overall rate of return of 6.06%, and CUB recommends an overall rate of return of 5.89%.[1882] The differences are attributable to a disagreement concerning Consumers' common equity balance, long-term debt, and proposed ROE.

A. Test Year Capital Structure

Recognizing the relative cost differences between debt and equity financing, the Commission has long determined that a balanced capital structure reflects equal amounts of debt and equity as a percentage of Consumers' permanent capital structure.

> The appropriate capital structure of a utility is based on considerations of cost and risk, and in accordance with these considerations, the Commission has from time to time adjusted a company's capital structure to one that was more reasonable. While a company with more debt is a financially riskier enterprise, a company with more equity has a greater amount of capital invested in the most expensive type of capital. Not only is equity capital more expensive than debt capital, but the return on equity adds a tax burden to total revenue requirements, whereas debt does not. Thus, the Commission seeks an appropriate balance between the risks and costs of investor and debt funding.

[1881] Consumers initial brief, p. 299; Ex. A-187.
[1882] Ex. S-4, Sch. D-1; Ex. AG-35; Ex. CUB-2.

> [T]he Commission has treated Consumers as a stand-alone company [which] has been predicated on the company maintaining "a capital structure roughly balanced between debt and equity." . . .[1883]
>
> . . .
>
> The Commission desires to arrive at an optimized capital structure that is both supportive of planned infrastructure investments, yet is not unnecessarily burdensome on ratepayers. The Commission also anticipates that a cycle of heavier-than-usual investment will present an ideal opportunity to rebalance Consumers' capital structure to reach its 50/50 goal.[1884]

See, also, Case No. U-18124

> Consumers' treatment as a stand-alone company for ratemaking purposes requires it to maintain a capital structure that is evenly balanced between debt and equity.
> . . .
>
> The Commission agrees with the Attorney General that, considering the size of Consumers' capital portfolios, a few percentage point increase to the equity balance translates into an increase of millions of dollars, and may unnecessarily increase costs to customers.[1885]

In Consumers' recent electric rate order, the Commission stated:

> The Commission further agrees . . the company has not demonstrated significant changes in the economic circumstances to support a deviation from a balanced capital structure. The Commission finds that a balanced capital structure most appropriately balances the interests of the utility's investors and customers, consistent with the holdings in *Bluefield* and *Hope*. As such, the Commission adopts a balanced capital structure of 50% debt to 50% equity utilizing the Attorney General's methodology.[1886]

1. Consumers

Mr. Bleckman states that Consumers is recommending a capital structure which represents the actual capital structure as of December 31, 2024, adjusted for the

[1883] Case No. U-17990, Order, February 28, 2017, p. 63. Citation omitted.
[1884] Id., p. 64.
[1885] Case No. U-18124, Order, June 7, 2012, p. 45-46.
[1886] Case No. U-21585, Order, March 21, 2025, p 232-233.

projected changes in debt, equity, deferred income taxes, and Investment Tax Credit ("ITC") through the end of the test year ending on April 30, 2027.[1887] He adds that the equity ratio as a percentage of permanent capital is 50.75%, with long-term debt and preferred stock at 49.25%.[1888] He states that the equity ratio as a percentage of total capital is 42.94%.[1889] He added that he determined the overall cost of capital for Consumers by assuming an a Return on Equity (ROE) of 10.25%.[1890]

Mr. Bleckman stated that capital structure refers to the amounts and mix of a company's financing components which make up the funds used for its operations and capital investment, and that for Consumers this includes long-term debt, common equity, preferred equity (or preferred stock), short-term debt, ITC, and deferred income taxes.[1891]

Mr. Bleckman stated that Consumers aims to finance its long-term capital (such as plant and property) with long-term debt (First Mortgage Bonds) and equity, and to finance short-term capital requirements (such as seasonal working capital needs) with short-term debt (borrowings under Consumers' credit facilities, including commercial paper and intercompany borrowings.)[1892]

Mr. Bleckman testified that common equity increases with net income (retained earnings) and with equity contributions from Consumers' parent, CMS Energy, and that

---

[1887] 3 Tr 810-811; Ex. A-14, Sch. D-1.
[1888] 3 Tr 811; Ex. A-14, Sch. D-1.
[1889] Id.
[1890] Id.
[1891] Id.
[1892] 3 Tr 812.

common equity decreases when Consumers makes dividend distributions to CMS Energy.[1893]

Mr. Bleckman states that he projected that the 13-month common equity balance for the test year will be $2.511 billion higher than the December 31, 2024 balance with the common equity adjustment consisting of two components: an adjustment to reflect $369 million in projected retained earnings on a weighted average basis from January 2025 through April 2027, and an adjustment of $2.142 billion to reflect the projected equity infusions on a weighted average basis from January 2025 through April 2027.[1894] He adds that to project the change in Consumers' retained earnings from January 2025 through the test period ending April 2027, he assumed Consumers' retained earnings rate to be $16.783 million per month, or $201.4 million per year, from January 2025 through April 2027, based on Consumers' long-standing policy of using an 80% dividend payout ratio.[1895]

Based on Consumers' SEC Form 10-K for 2024, Mr. Bleckman states that he determined that Consumers' net income for the 12-month period ending December 31, 2024, was $1.007 billion and, using that amount as a proxy for the future net income and assuming a dividend payout ratio of 80%, he calculated an annual retained earnings amount of $201.4 million.[1896]

Mr. Bleckman states that he made a $2.142 billion adjustment for the new equity infusions in his recommended capital structure as this is the amount needed to hold a

---

[1893] Id.
[1894] 3 Tr 813.
[1895] 3 Tr 814.
[1896] Id.; Ex. A-14, Sch. D-1a, p. 3.

50.75% equity ratio for the test period in this case.[1897] He adds that CMS Energy made an equity infusion of $150 million in February 2025 and plans to make equity infusions of $275 million by May 2025, $425 million by June 2025, $40 million by October 2025, $525 million by February 2026, $675 million by June 2026, and $675 million by February 2027.[1898]

Mr. Bleckman states that peer-authorized equity ratios are higher and are trending up.[1899] He notes that the average equity ratio for the peer group was 51.85%, 110 basis points higher than the 50.75% proposed for Consumers in this case.[1900] He states that the utilities he used for comparison purposes are at the regulated subsidiary level.[1901] He notes that in its Order in Case No. U-20963, the Commission stated that "regulatory and financial data should not be combined" with such an analysis.[1902]

Mr. Bleckman states that equity ratios for regulated utilities have increased over the last several years, as highlighted in a December 2023 Wells Fargo report on approved equity ratios.[1903] He adds that while the Wells Fargo report shows an increase in approved electric utility equity ratios of 130 basis points from 2019 to 2023, Consumers' authorized equity ratio has decreased 205 basis points from 2019 (Case No. U-20322) to present, which he asserts weakened credit quality and put Consumers' credit rating at risk. He asserts that the proposed an equity ratio of 50.75% taken together with an ROE of 10.25% is the minimum amount that reflects the appropriate

---

[1897] Id.
[1898] 3 Tr 814-815; Ex. A-14, Sch. D-1a, p. 1, 3.
[1899] 3 Tr 815; Ex. A-29.
[1900] 3 Tr 816.
[1901] Id.
[1902] 3 Tr 817.
[1903] Id., Ex. A-31.

level that the Commission should adopt to help preserve Consumers' current credit rating.[1904]

Mr. Bleckman that a key financial metric used by rating agencies is the ratio of Funds From Operations ("FFO") to Debt ("FFO/debt ratio"), which calculation includes, in part, both the equity ratio and the authorized ROE of Consumers.[1905] He asserts that there needs to be a balance between Consumers' equity ratio and ROE that will ensure that this key financial metric does not degrade and cause significant credit deterioration, and that an equity ratio of 50.75% and an ROE of 10.25%, results in an FFO/debt ratio that is sufficient in striking this balance.[1906] He adds that a higher FFO/debt ratio, which reflects a higher level of cash flow from operating activities to offset or otherwise reduce the risk associated with Consumers' ability to pay its debts, is viewed favorably and indicative of a lower financial risk and a resulting higher relative credit rating, which higher credit rating, in turn, results in lower financing rates.[1907]

Mr. Bleckman states that because ROE and equity ratio are two inputs in determining Consumers' ratio of FFO to Debt, and FFO/debt ratios are used by credit agencies to determine Consumers' financial health, it is important to recognize that Consumers' ROE and equity ratio cannot be evaluated in isolation, but should be viewed as interconnected components that determine Consumers' overall financial

[1904] 3 Tr 818.
[1905] Id.
[1906] Id.
[1907] 3 Tr 818-819.

health.[1908] He asserts that a lower authorized ROE would necessitate a higher approved equity ratio to maintain the same level of financial health.[1909]

Mr. Bleckman states that Consumers' FFO/debt ratio as calculated by Standard and Poor's ("S&P") has been trending down in recent years from 21.7% in 2021 to 17.6% in 2023, a decrease of 410 basis points and, for 2023, 40 basis points below the low end of S&P's expected range outlined in its August 2023 report.[1910] He adds that Consumers' FFO/debt ratio as calculated by Moody's Investors Service ("Moody's") has also been trending down in recent years from 22.6% in 2021 to 19.1% in 2023, a decrease of 350 basis points, and that Moody's May 2024 credit report also shows a further decline to 18.7% for the 12 months ended March 2024.[1911]

Mr. Bleckman asserts that new circumstances, including a high degree of volatility and economic uncertainty has emerged in recent months with respect to financial markets, interest rates, and geopolitical tensions, could have material impacts on Consumers' credit metrics during the test year.[1912] He adds that heightened trade tensions created an atmosphere of uncertainty that negatively affected business investment and led to heightened volatility in financial markets.[1913] He argues that these developments represent a material change in Consumers' risk environment since the previous Commission orders that will most likely continue through the test year of this case.[1914] He asserts that during this period of heightened risk and volatility, it will be

---

[1908] 3 Tr 819.
[1909] Id.
[1910] 3 Tr 820.
[1911] 3 Tr 820-821.
[1912] 3 Tr 821-822.
[1913] 3 Tr 822.
[1914] Id.

critical for Consumers to have an authorized ROE and equity ratio that is supportive of its good credit quality, which will be instrumental in Consumers' ability to maintain uninterrupted access to needed liquidity and better withstand potential impacts from fuel price spikes, inflationary pressures, and tightening capital markets.[1915]

Mr. Bleckman states that Consumers is making significant capital investments to maintain and improve infrastructure and that during this time, Consumers will rely heavily on the capital markets to fund these investments, thus asserting that it will be especially important for Consumers to maintain strong credit ratings over this period.[1916] He asserts that Consumers has saved customers $152 million annually as a result of improved credit ratings and lowered interest costs.[1917]

Mr. Bleckman argues that if the Commission demonstrates a pattern of consistent, constructive rate orders, it contributes favorably to Consumers' credit quality and credit rating, and that the authorized equity ratio and ROE are two important components in the rating agencies' assessment of the regulatory environment.[1918] He adds that in August 2024, S&P lowered its ranking of Michigan's regulatory environment from "Above Average" to "Average."[1919] He states that 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."[1920] He states that in updating its regulatory rankings for U.S. utilities in May 2023, UBS downgraded Michigan from Tier 1 to Tier 2,

---

[1915] Id.
[1916] 3 Tr 823.
[1917] Id.
[1918] 3 Tr 824.
[1919] Id.; Ex. A-33.
[1920] Id.

with UBS specifically mentioning authorized ROEs ranking in the 3rd quintile 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."[1921] He concludes that it is apparent that rating agencies and analysts are taking note of Consumers' regulatory outcomes and are viewing them unfavorably, and that a continuation or a further degradation of the authorized equity ratio and ROE puts Consumers' at risk of dropping further in its regulatory environment rankings which could negatively impact Consumers' credit quality and credit rating.[1922]

Mr. Bleckman states that **i**n a February 2024 report, 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.[1923] He adds that 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."[1924] He asserts that It is apparent from this S&P report that a supportive ROE and equity ratio is critical in maintaining a "financial cushion" to protect against downgrade in the event of unforeseen events like the market volatility and disruption that occurred during the onset of the COVID-19 pandemic in 2020 or the financial pressure caused by the dramatic increase in gas prices and interest rates in 2022 or the banking crisis of 2023.[1925]

[1921] 3 Tr 825.
[1922] Id.
[1923] 3 Tr 825-826; Ex. A-35.
[1924] 3 Tr 826.
[1925] Id.

Mr. Bleckman states that an equity ratio of 50.75% and an ROE of 10.25% as proposed by Consumers in this case is the optimal outcome for Consumers and its customers.[1926]

Mr. Bleckman states that he projected that the average debt balance for the test year ending April 30, 2027, will be $2.073 billion higher than the December 31, 2024 balance.[1927] He adds that the planned debt issuances in May 2025, August 2025, May 2026, and August 2026 will be used for general corporate purposes of Consumers including financing capital expenditures, with the debt planned to be issued in May 2026 also being used for the retirement of Consumers' $115 million 5.24% bonds which mature in May 2026.[1928]

Mr. Bleckman states that he projected an average short-term debt balance for the test year of $148 million.[1929]

Mr. Bleckman states that Consumers strives to match long-term investments with long-term financing and to finance short-term liquidity needs with its cash and short-term borrowing facilities.[1930] He adds that due to the seasonal nature of utility cash inflows and outflows, Consumers generally holds more cash in the spring and summer months and relies on short-term borrowing in the fall and winter months, and that throughout the year, however, a minimum level of cash on hand is maintained.[1931]

[1926] 3 Tr 827.
[1927] Id.; Ex. A-14, Sch. D-1a.
[1928] 3 Tr 828.
[1929] Id.; Ex. A-14, Sch. D-1a, Sch. D-3.
[1930] 3 Tr 831.
[1931] 3 Tr 831-832.

Mr. Bleckman states that Consumers' Tax Department has projected that the average deferred income tax balance for the test year ending April 30, 2027, will be $404 million higher than the December 31, 2024 balance.[1932]

2. Staff

Staff recommends a capital structure with a permanent equity to debt layer of 50/50[1933] Mr. Megginson stated that Standard & Poor's (S&P) rates Consumers' senior secured debt "A", which was raised from "A-" on December 4, 2014; that Moody's rates Consumers' senior secured debt "A1", which was lowered from "Aa3" in May 2021; and Fitch rates Consumers' senior secured debt "A+", which was raised two notches from "A-" in March 2016.[1934] He adds that the rating agencies held Consumers' credit rating stable over the years, noting that S&P has held Consumers' credit rating steady for approximately 10 years and Fitch has held it steady for over eight years.[1935] He adds that Moody's one notch downward revision from Aa3 (equivalent to S&P's AA- rating) in 2021 put Consumers' credit rating more in line with the other two agencies ratings.[1936]

Mr. Megginson states that the credit rating agencies acknowledge that Consumers currently has a stable foundation for its credit rating, and that Michigan has a very equitable regulatory environment that is supportive of a utility's ongoing business and financial health.[1937]

Mr. Megginson states that Staff agreed with the Consumers' long-term debt balance but modifying Consumers' capital structure by $435 million to balance the

---

[1932] 3 Tr 835; Ex. A-14, Sch. D-1a.
[1933] 6 Tr 4524, 4531.
[1934] 6 Tr 4524
[1935] Id.
[1936] 6 Tr 4524-4525.
[1937] 6 Tr 4526.

capital structure to the 50/50 level that Staff recommends.[1938] To that end, he adopted Consumers' common equity balance through April 2027 of $13,916 million and then reduced Consumers' equity balance by $180 million, which resulted in a common equity balance of $13,720 million and a ratemaking equity ratio of 50.0%.[1939]

Mr. Megginson states that he modified Consumers long-term debt and common equity balances primarily to abide by the Commission's repeated directives over the years for Consumers to move its ratemaking capital structure from an equity layer well over 50%, to an equity layer equivalent with its LT-debt layer unless extraordinary circumstances prevent that from occurring.[1940] In support, he quotes from Consumers' recent electric rate order in Case No. U-21585 wherein the Commission stated:

> The Commission further agrees…the company has not demonstrated significant changes in the economic circumstances to support a deviation from a balanced capital structure. The Commission finds that a balanced capital structure most appropriately balances the interests of the utility's investors and customers, consistent with the holdings in *Bluefield* and *Hope*. As such, the Commission adopts a balanced capital structure of 50% debt to 50% equity utilizing the Attorney General's methodology.[1941]

Mr. Megginson states that equity is clearly costlier to ratepayers than debt and the need to balance both items is as important today as it has been in past rate cases.[1942] He adds that an approved equity layer of 50%, instead of 50.75%, will save ratepayers about $9.0 million annually.[1943]

[1938] 6 Tr 4530-4531.
[1939] 6 Tr 4531.
[1940] Id.
[1941] 6 Tr 4531-4532, quoting Case No. U-21585, Order, March 21, 2025, p 232-233.
[1942] 6 Tr 4533.
[1943] 6 Tr 4534.

3. Attorney General

Mr. Coppola recommends a capital structure following Consumers' proposed capital structure with an adjustment made up of an increased the long-term debt component by $207 million and reduced the common equity component by the same amount, resulting is a capital structure with 50% of common equity and 50% of debt and preferred stock.[1944] He states that he made the adjustment to reduce Consumers' proposed capital structure common equity component of 50.75% to the 50% equity ratio approved by the Commission in Consumers' last two fully contested rate cases, Case Nos. U-21585 and U-21389.[1945]

Mr. Coppola states that there are several factors which clearly support a 50% common equity level, including:

> (1) the Commission's consistent directive in the Company's prior electric and gas rate cases, which stated that a 50/50 capital structure is desirable and appropriate to ensure reduced costs to customers and maintain the Company's strong financial position, unless the Company can demonstrate that a higher ratio is justified; (2) The Company's strong cash flow to debt coverage ratio and credit ratings; (3) the Company's common equity capital contributions by the parent company, albeit often funded with long term debt issued at the parent company level; (4) the favorable regulatory environment in Michigan supported by historical returns on common equity above industry averages and in the top tier of the Company's peer group; and (5) the fact that the common equity ratio of the peer group, used to assess the cost of common equity in this case, is approximately 42%.[1946]

Mr. Coppola states that in the recent March 21, 2025 order in Case No. U-21585, the Commission decided to set the common equity ratio at 50%, as recommended by the ALJ and supported by the Attorney General and other parties, and adds that in this rate

---

[1944] 3 Tr 2514; Ex. AG-33.
[1945] Id. Citations omitted.
[1946] 3 Tr 2515, citing Ex. AG-38.

case, Consumers has not provided any new evidence or persuasive arguments as to why the Commission should veer from its stated goal of a 50/50 debt/equity capital structure for the Company.[1947]

Mr. Coppola states that his analysis shows that the 9.80% ROE and 50% common equity ratio would result in Consumers' cash flow ratios being well above the long-term threshold levels that might result in a credit downgrade by the credit reporting agencies.[1948] He adds that the credit rating agencies current outlook for Consumers do not include any significant concerns, quoting in part from Moody's May 29, 2025 report: "The stable outlook reflects our expectation that financial metrics will remain stable and that Consumers Energy will continue to benefit from a consistent and generally credit supportive regulatory environment."[1949]

4. ABATE

Mr. Walters states that in general, the utility industry's common equity ratio has not deviated much from the range of 50.0% to 52.0%.[1950] He adds that his compilation of authorized common equity ratios for utilities around the country excludes four states including Michigan because these states include sources of capital outside of investor-supplied capital such as accumulated deferred income taxes.[1951]

Mr. Walters states that Consumers' proposed equity ratio of 50.75% is relatively higher than the equity ratio for the proxy group he used to estimate the cost of equity for Consumers, with the proxy group having an average common equity ratio of 40.1%

[1947] 3 Tr 2516.
[1948] 3 Tr 2516-2521; Ex. AG-47, Ex. AG-48.
[1949] 3 Tr 2521-2522; Ex. AG-47 (Confidential).
[1950] 6 Tr 3750.
[1951] Id., Table CCW-2.

(including short-term debt) and 43.8% (excluding short-term debt), which indicates that Consumers has less financial risk compared to the proxy group.[1952]

Mr. Walters notes that for several rate case cycles now, this Commission has consistently authorized an equity ratio of 50.0% for the major utilities it regulates including DTE Electric, DTE Gas, as well as both of Consumers' operating gas and electric divisions.[1953] He adds that the Commission reiterated that stance in Consumers' recent electric rate case (Case No. U-21585), stating in its Order that it "finds that the balanced capital structure most appropriately balances the interests of the utility's investors and customers, consistent with the holdings in *Bluefield* and *Hope*.[1954] He asserts that Consumers has not presented any credible evidence to depart from the Commission's stated preference and in support of increasing its authorized equity ratio from 50.0% to 50.75%.[1955]

Accordingly, he recommends that the Commission continue to authorize Consumers its currently authorized equity ratio of 50.0%.[1956]

5. CUB

CUB recommends that the Commission maintain Consumers' authorized capital structure of 50% common equity and 50% long-term debt.[1957]

Mr. Bandyk states that the cost of equity is always higher than the cost of debt because equity holders inherently take on more risk because they come second to debt holders when it comes to the legal ownership of the assets of the firm, and because

---

[1952] 6 Tr 3766.
[1953] Id.
[1954] 6 Tr 3767.
[1955] Id.
[1956] Id.
[1957] 6 Tr 3978.

interest payments on debt are tax deductible, reducing the cost of financing with debt.[1958] He adds that as a result of the higher cost of equity, financing a firm with greater amounts of equity tends to be more expensive than financing with greater amounts of debt, and in the context of a utility, leads to higher costs for ratepayers.[1959]

Mr. Bandyk states that his analysis shows that Consumers could use less equity in its capital structure and still maintain the same credit rating.[1960] He adds that the result of his analysis shows that Consumers' proposed capital structure would unnecessarily burden ratepayers due to an excessive amount of equity.[1961] He states that, by comparing his calculation of Consumers' interest coverage ratio – which measures a company's ability to pay its interest obligations – with the coverage ratios for companies with a bond credit rating similar to Consumers, Consumers could lower the equity share in its capital structure, and thus lower its cost of capital, without materially increasing financial risk.[1962]

Mr. Bandyk states that an equity ratio and ROE lower than Consumers' proposal would result in a more optimal outcome because it would minimize the cost of capital, reducing costs for customers.[1963] He disagrees with Mr. Bleckman assertion that Consumers' proposed equity ratio and ROE results in an "optimal outcome" for Consumers and its customers, asserting that Mr. Bleckman does not provide any quantitative analysis as to how Consumers' proposal is optimal while he simply asserts that the impact on customer rates is "reasonable" without explaining why customers

---

[1958] 6 Tr 3974.
[1959] Id. Citation omitted.
[1960] 6 Tr 3975.
[1961] Id.
[1962] 6 Tr 3975-3976; Ex. CUB-9. Citations omitted.
[1963] 6 Tr 3976.

should have to pay for a higher rate of return without a corresponding benefit.[1964] Regarding Mr. Bleckman's assertion that "further degradation of the authorized equity ratio and ROE" puts Consumers at risk of dropping further in its regulatory environment rankings which could negatively impact Consumers' credit quality and credit rating, he counters that Mr. Bleckman does not provide any evidence that Consumers is at risk of a credit downgrade from a drop in regulatory environment rankings or why his preferred equity ratio and ROE would prevent such a drop from occurring.[1965] He adds that both Moody's and S&P have a "stable" outlook for Consumers, meaning they see little risk of a downgrade.[1966] Regarding Mr. Bleckman's assertion that Consumers' credit rating is put "at risk" from the lower Funds from Operations (FFO)-to-Debt ratio that would result from a lower equity ratio and/or ROE, he counters that Mr. Bleckman admitted in a discovery response that "a calculation of the FFO-to-Debt ratio is not feasible using only the proposed 50.75% equity ratio and 10.25% ROE," such that Mr. Bleckman cannot possibly know if the FFO-to-Debt ratio resulting from the proposed equity ratio and ROE would be "sufficient" toward preserving Consumers' credit rating, or if a lower equity ratio and/or ROE would be insufficient.[1967]

Accordingly, Mr. Bandyk recommends the Commission maintain Consumers' authorized capital structure of 50% common equity and 50% long-term debt.[1968]

[1964] 6 Tr 3976-3977.
[1965] 6 Tr 3977.
[1966] Id.
[1967] 6 Tr 3978
[1968] Id.

6. Rebuttal

In rebuttal, Mr. Bleckman states that Mr. Megginson minimizes the importance of Moody's downgrade of Consumers' credit rating, asserting that regardless of the presumed comparative credit ratings between the different credit rating agencies the fact that Consumers' credit rating was downgraded by Moody's was a negative event that had negative financial consequences for Consumers and for customers who bear the cost of capital.[1969]

Noting that Mr. Megginson references credit reports in which Consumers' regulatory environment has been described as positive, Mr. Bleckman counters that Mr. Megginson's assessment Consumers' regulatory environment is incomplete, as Mr. Megginson's assessment fails to capture the results from Consumers' 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, which decline could be seen as a material deterioration in the credit supportiveness of the Michigan regulatory environment.[1970] He adds that analysts have started to recognize a decline in the state of Consumers' regulatory environment, noting that in August 2024, S&P lowered its ranking of Michigan's regulatory environment from "Above Average" to "Average."[1971] He asserts that 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.[1972] He asserts that a continuation or, even worse, a further degradation of the authorized weighted rate of return puts Consumers at risk of dropping further in its regulatory

[1969] 3 Tr 869.
[1970] 3 Tr 870.
[1971] 3 Tr 871; Ex. A-33, Ex. A-34.
[1972] Id.

environment rankings which could negatively impact Consumers' credit quality and credit rating, and that Michigan's regulatory standing needs to be protected and bolstered rather than drawn upon to push Consumers toward over-leveraging.[1973]

Regarding Mr. Megginson's statement that "the Michigan commission is rated Average/1, which is in the upper tier of 4 the national average, in terms of utility credit supportive regulation," Mr. Bleckman counters that while Michigan is in the higher end of the "Average" tiers, the state is no longer in the "Above Average" category.[1974]

Noting Mr. Megginson's assertion that Consumers' increased net income has "enabled Consumers to access credit markets for billions in short and long-term financing at very competitive rates.", Mr. Bleckman states that Consumers' 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 Consumers' credit quality as determined by credit rating agencies.[1975]

Mr. Bleckman states that Consumers has saved customers $152 million annually as a result of improved credit ratings and lowered interest costs.[1976]

Mr. Bleckman states that Staff's, the Attorney General's, ABATE's and CUB's recommended 50.00% equity ratio is significantly lower than equity ratios authorized by other commissions, noting that the average authorized equity ratio for the peer group was 51.85%.[1977]

[1973] Id.
[1974] 3 Tr 872, citing Ex. A-33, p. 9.
[1975] 3 Tr 873-874.
[1976] 3 Tr 882, citing Ex. A-32.
[1977] 3 Tr 883; Ex. A-29.

Noting that in Case No. U-20963, the Commission cited Staff's average ROE analysis as one of the factors considered in determining Consumers' approved ROE, Mr. Bleckman asserts that it is apparent that the Commission considers peer averages an important piece of evidence to inform the ratemaking process, and that to be consistent with that philosophy, it is appropriate to consider peer company equity ratio averages and trends in determining the equity ratio for Consumers in this case.[1978]

Noting that Mr. Bandyk references a discovery response in which Consumers did not identify a specific FFO-to-Debt ratio that would trigger a credit downgrade, Mr. Bleckman states that 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.[1979]

After reviewing the record and the arguments of the parties, this PFD finds that Consumers has not established that its request for a capital structure with an equity ratio of 51.75% is reasonable and consistent with prior Commission orders.

As indicated, the Commission has determined that a balanced capital structure -- reflecting equal amounts of debt and equity as a percentage of Consumers' permanent capital structure – most appropriately balances the interests of the utility and its customers.

> While a company with more debt is a financially riskier enterprise, a company with more equity has a greater amount of capital invested in the most expensive type of capital. Not only is equity capital more expensive than debt capital, but the return on equity adds a tax burden to total revenue requirements, whereas debt does not.[1980]

[1978] 3 Tr 886.
[1979] 3 Tr 931.
[1980] Case No. U-17990, Order, February 28, 2017, p. 63.

In Consumers' recent electric rate order, the Commission stated:

> The Commission further agrees…the company has not demonstrated significant changes in the economic circumstances to support a deviation from a balanced capital structure. . . The Commission finds that a balanced capital structure most appropriately balances the interests of the utility's investors and customers, consistent with the holdings in *Bluefield* and *Hope*. As such, the Commission adopts a balanced capital structure of 50% debt to 50% equity utilizing the Attorney General's methodology.[1981]

Staff, the Attorney General, ABATE and CUB all recommend that the Commission keep Consumers' capital structure evenly balanced between debt and equity.[1982] Although Consumers offers various arguments in favor of increasing the equity ratio, this PFD finds those arguments to be unpersuasive.

Consumers argues that its credit rating could be lowered if core financial measures underperform. However, a review of the recent credit reports indicates that Consumers has a good credit rating which likely will not be affected by keeping the capital structure equally balanced.

Mr. Megginson states that Standard & Poor's (S&P) rates Consumers' senior secured debt "A", which was raised from "A-" on December 4, 2014; that Moody's rates Consumers' senior secured debt "A1", which was lowered from "Aa3" in May 2021; and Fitch rates Consumers' senior secured debt "A+", which was raised two notches from "A-" in March 2016.[1983] He adds that S&P has held Consumers' credit rating steady for approximately 10 years and Fitch has held it steady for over eight years, and that Moody's one notch downward revision from Aa3 (equivalent to S&P's AA- rating) in

[1981] Case No. U-21585, Order, March 21, 2025, p 232, 233.
[1982] 6 Tr 4524, 4531; 3 Tr 2514; 6 Tr 3750; 6 Tr 3978.
[1983] 6 Tr 4524

2021 put Consumers' credit rating more in line with the other two agencies ratings.[1984] Similarly, Mr. Coppola quotes from Moody's May 29, 2025 report: "The stable outlook reflects our expectation that financial metrics will remain stable and that Consumers Energy will continue to benefit from a consistent and generally credit supportive regulatory environment."[1985]

Consumers argues that Staff is downplaying the importance of Moody's 2021 downgrade of Consumers' credit rating by asserting that the downgrade put Consumers' credit rating "more in line with the other two agencies ratings."[1986] This PFD disagrees, noting that Consumers does not provide any evidence that the downgrade has affected Consumers' ability to maintain its credit or attract capital. Moreover, the Commission previously agreed with Staff's assertion, finding that "prior to the downgrade", Moody's credit rating for Consumers "was overstated" and that even after this downgrade, Consumers "still has a healthy credit rating."[1987]

Noting that Consumers is making significant capital investments over the next five years, Mr. Bleckman asserts that Consumers will rely heavily on the capital markets to fund these investments, and thus that it is important for Consumers to maintain strong credit ratings over this period.[1988] However, the credit reporting agencies do not indicate that Consumers' capital expenditure program is a concern. Indeed, Moody's states that its "stable outlook" incorporates Moody's view that Consumers "will maintain prudent financial policies while managing through its robust investment cycle and that

---

[1984] Id.; 6 Tr 4524-4525.
[1985] 3 Tr 2521-2522; Ex. AG-47 (Confidential).
[1986] 3 Tr 869.
[1987] Case No. U-20963, Order, December 22, 2021, p. 220.
[1988] 3 Tr 283.

debt levels at the parent will not increase materially."[1989] Moreover, rather than being a concern possibly affecting its equity ratio, the Commission has stated that "a cycle of heavier-than-usual investment will present an ideal opportunity to rebalance Consumers' capital structure to reach its 50/50 goal."[1990]

In support of raising its equity ratio to 50.75%, Consumers relies heavily on a purported "key" credit metric, the FFO/debt ratio, arguing that there needs to be a balance between Consumers' equity ratio and ROE that will avoid significant credit deterioration, and that Consumers' proposed equity ratio of 50.75% together with its proposed ROE of 10.25% is sufficient in striking this balance.[1991]

Mr. Bleckman argues that equity ratio and ROE should be viewed as "interconnected components" that determine Consumers' overall financial health, such that a lower authorized ROE necessitates a higher approved equity ratio to maintain the same level of financial health.[1992] These assertions are problematic and unsupported.

The various factors that the Commission considers in assessing what may be a reasonable equity ratio and the various factors that the Commission considers in assessing what may be a reasonable ROE are not the same. In addition, the Commission has not recognized the asserted linkage between equity balance and ROE that Consumers proposes. Indeed, the only apparent linkage between equity balance and ROE seems to be that these are both inputs, included among other inputs, in determining a company's FFO/debt ratio by the credit rating agencies.[1993]

[1989] Ex. AG-47, p. 3. (Confidential.)
[1990] Case No. U-17990, Order, February 28, 2017, p. 64.
[1991] 3 Tr 818.
[1992] 3 Tr 819.
[1993] See, e.g., 4 Tr 435.

Moreover, this proposed balance between these two inputs is fundamentally at odds with the calculation of the FFO/debt ratio and the purpose for which the ratio is considered. Consumers' purported linkage of equity ratio and ROE serves to elevate the importance of these two inputs over other inputs to the calculation, such as debt. Certainly, as recognized by the other parties and the credit rating agencies, if Consumers' debt balance was to change, its FFO/debt ratio could also change with or without a material change to either Consumers' equity ratio and/or its ROE.

Similarly, Consumers' proposed linkage also tends to elevate the significance of this particular credit metric ratio over other credit metrics. This PFD notes that under Moody's credit rating methodology, its CFO pre WC/debt ratio is one of four ratios included in its Financial Strength category, which category collectively is weighted at 40%.[1994]

Referencing a December 2023 Wells Fargo report (Ex. A-31), Mr. Bleckman argues that while equity ratios for regulated utilities have increased over the last several years, Consumers' authorized equity ratio has decreased from 2019, which he asserts has weakened credit quality and put Consumers' credit rating at risk.[1995] However, this PFD notes that this same argument was recently rejected by the ALJ and the Commission in Consumers' last electric rate case (Case No. U-21585). In her PFD, the ALJ concluded that the Wells Fargo report could be interpreted to support Consumers' current capital structure "because it shows that for a majority of the last 10 years covered by the report, i.e. from 2013-2023, the median equity ratio hovered at or very

[1994] Ex. AG-47, p. 9. Confidential.
[1995] 3 Tr 817-818.

close to 50.0%, i.e. the equity ratio targeted by the Commission."[1996] The ALJ concluded that "even when considering a relatively recent trend of increasing equity ratios, the 50.0% equity ratio targeted by the Commission is hardly unreasonable or an outlier."[1997] The Commission adopted the "thorough and well-reasoned findings" of the ALJ.[1998]

Mr. Bleckman states that a degrading of the authorized equity ratio and ROE puts Consumers at risk of dropping in its regulatory environment rankings, which could negatively impact Consumers' credit rating.[1999] However, while quoting from recent credit reports – "Michigan's regulatory construct [is] above average compared to peers" (S&P); "The regulatory framework in Michigan [is] more credit supportive than most other states" (Moody's); "The (regulatory) framework remains constructive from a credit perspective" (Fitch) – Mr. Megginson asserts that that Consumers has a "stable foundation for its credit rating" and that Michigan is a "very equitable regulatory environment" that is supportive of a utility's business and financial health. This PFD agrees.[2000]

Moreover, Mr. Bandyk asserts that Mr. Bleckman does not provide any evidence that Consumers is at risk of a credit downgrade from a drop in regulatory environment ranking, nor any analysis showing that Consumers' proposed equity ratio and ROE are required to maintain Consumers' credit ratings.[2001] Again, this PFD agrees.

Mr. Bleckman argues that a high degree of volatility and economic uncertainty has emerged in recent months with respect to financial markets, interest rates, and

---

[1996] Case No. U-21585, PFD, January 27, 2025, p. 306.
[1997] Id., p. 306-307.
[1998] Case No. U-21585, Order, March 21, 2025, p. 233.
[1999] 3 Tr 825.
[2000] 6 Tr 4525-4526. Citations omitted.
[2001] 6 Tr 3977.

geopolitical tensions, which represent a material change in Consumers' risk environment since the previous Commission orders that will most likely continue through the test year of this case.[2002] He asserts that it will be critical for Consumers to have an authorized ROE and equity ratio to maintain uninterrupted access to needed liquidity and better withstand potential impacts from fuel price spikes, inflationary pressures, and tightening capital markets.[2003] However, this argument does not support increasing Consumers' equity ratio from its current 50% level. *See*, Return on Equity discussion, *infra*.[2004]

After reviewing the record and the arguments of the parties, this PFD finds that Consumers has not established that its request for a changed capital structure with an increased equity ratio of 50.75% is reasonable and consistent with prior Commission orders. Conversely, having reviewed the evidence and arguments presented by Staff, the Attorney General, ABATE, and CUB, this PFD finds that the evidence presented supports maintaining a balanced capital structure. Thus, this PFD recommends adopting the Attorney General's methodology for maintaining a balanced 50/50 equity ratio, i.e. increasing debt and decreasing equity.

Lastly, noting that in its Order in Case No. U-21585, the Commission instructed Consumers in its next electric rate case to "provide a more thorough explanation of its renewables liability short-term debt process, consistent with the Commission Staff's recommendations in this case." The primary concern expressed by Staff witness Kirk

---

[2002] 3 Tr 880.
[2003] Id.
[2004] Issues related to credit ratings and metrics, the regulatory environment, and current and projected economic conditions are discussed both in the Capital Structure and ROE sections of this PFD because Consumers presents overlapping arguments regarding these issues. Thus, these two sections should be read together to thoroughly address the various arguments relating to these topics.

Megginson in Case No. U-21585 was that the renewables liability -- representing excess funds collected through Consumers' renewable energy program -- is improperly "being charged back to customers as a form of short-term debt,"

Mr. Bleckman stated that interest on the renewable liability reduces the revenue requirement in Consumers' renewable energy case and thus, there is a benefit to customers.[2005] He added that in previous rate cases, Consumers has consistently included the renewables liability as a component of short-term debt in its general rate case capital structure projections consistent with energy legislation.[2006] He states that, while not projected or included in the current case, Consumers is not opposed to excluding a renewables liability balance from its capital structure should a liability be projected in future cases.[2007] He asserts that Consumers' treatment of the renewables liability has been in compliance with long-standing ratemaking history and Michigan legal precedent. He adds that the Commission has approved this methodology since the beginning of the renewable portfolio requirements of Public Act 295 in 2008.[2008] He asserts that removing the renewables liability from the capital structure would effectively increase albeit marginally Consumers' total cost of capital used in the rate case revenue requirement calculation.[2009] He reiterates that Consumers does not object to excluding the renewables liability balance from its capital structure should a liability balance be projected in the future.[2010]

[2005] 3 Tr 49.
[2006] 3 Tr 49-50.
[2007] 3 Tr 50.
[2008] Id.
[2009] Id.
[2010] 3 Tr 51.

B. Overall Rate of Return

1. Long-Term Debt Balance

Consumers proposed a long-term debt balance of $13,465 million, based on Consumers' actual long-term balance as of December 31, 2024 with adjustments to reflect planned debt issuances and debt retirements.[2011] Staff recommends a $13,683 billion long-term debt, having adopted Consumers' long-term debt balance and then adding a modification to support Staff's recommended 50/50 capital structure.[2012] The Attorney General proposes utilizing a long-term debt balance of $13, 672, which represents Consumers' long-term balance as adjusted to reach a debt/equity ratio of 50%.[2013] This PFD finds that the modifications made by Staff and the Attorney General to achieve a balanced debt/equity ratio are appropriate, and thus recommends the Attorney General's long-term debt balance of $13,672 be adopted. This PFD notes that while Staff's proposed modification is similar in concept to that made by the Attorney General, the Attorney General's modification still resulted in a total capital balance at the same amount as Consumers' total capital balance ($27,418 billion), while Staff's modification resulted in a greater total capital amount ($27,440 billion) than Consumers' projected total capital balance.

2. Short-Term Debt Balance

Mr. Bleckman projected an average short-term debt balance for the test year of $148 million.[2014] The short-term debt balance recommended by Staff and the Attorney

[2011] Consumers initial brief, p. 194: Ex. A-14, Sch. D-1; Ex. A-14, Ach. D-1a, p. 1.
[2012] Staff initial brief, p. 69-70; Ex. S-4, Sch. D-1.
[2013] Attorney General initial brief, p. 137; Ex. AG-35.
[2014] Consumers initial brief, p. 227; Ex. A-14, Sch. D-1, p. 1; Ex. A-14, sch. D-1a, p. 1.

General is the same as recommended by Consumers.[2015] Thus, this PFD recommends that the Commission adopt Consumers' short-term debt balance.

3. Deferred FIT Balance

Mr. Bleckman proposed a deferred tax balance for the test year of $4.692 billion.[2016] Staff and the Attorney General agreed with this deferred tax balance.[2017] Thus, this PFD recommends that the Commission adopt Consumers' deferred FIT balance.

4. Other Capital Structure Balances

Consumers, Staff, and the Attorney General used balances for preferred stock corresponding to balances in the historical period.[2018] For the test year Job Development Investment Tax Credit ("JDITC") balance, Mr. Bleckman testified that Consumers estimates the average balance will be $148 million based on internal projections from Consumers' Tax Department, with components for JDITC based upon the allocation of long-term debt, preferred stock, and common equity.[2019] This is the same amount recommended by Staff and the Attorney General.[2020] Thus, this PFD recommends that the Commission adopt Consumers' preferred stock balance and JDITC balance.

[2015] Ex. S-4, Sch. D-1; Ex. AG-35.
[2016] Ex. A-14, Sch. D-1; Ex. A-14, Sch. D-1a.
[2017] Ex. S-4, Sch. D-1; Ex. AG-35.
[2018] Ex. A-14, Sch.D-1a; Ex. S-4, Sch.D-1; Ex. AG-35.
[2019] 3 Tr 835-836; Ex. A-14, Sch. D-1a.
[2020] Ex. S-4, Sch. D-1; Exhibit AG-35.

C. Cost Rates

1. Return on Common Equity

A utility's cost of common equity, generally referred to as the return on equity (ROE), is the return that investors expect to provide the utility with capital for use in its various operations. The cost of this capital essentially represents an opportunity cost; in order to induce investors to purchase common stock or bonds, there must be the prospect of receiving earnings sufficient to make the investment attractive when compared to other investment opportunities.

The standards for establishing a fair rate of return for public utilities are set forth in the United States Supreme Court cases *Bluefield Water Works Co. v. Public Service Commission of West Virginia*, 262 US 679 (1923) and *Federal Power Comm. V. Hope Natural Gas Co*., 320 US 591 (1944). In *Bluefield*, the Supreme Court stated:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[2021]

In *Hope*, the Court stated:

> The rate-making process under the Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus, . . 'regulation does not insure that the business shall produce net revenues.' . . . [T]he investor interest has a legitimate

[2021] 262 U.S. at 692-693.

> concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[2022]

See, *also*, *Wilcox v. Consolidated Gas Co. of New York*, 212 U.S. 19, 48-49, 29 S. Ct. 192 (1909) where the Supreme Court, having stated that the "amount of risk in the business is a most important factor" in determining an adequate return for the utility, describes the minimal risk for New York's gas company in 1909:

> [There is no particular rate of compensation which must, in all cases and in all parts of the country, be regarded as sufficient for capital invested in business enterprises. Such compensation must depend greatly upon circumstances and locality; *among other things, the amount of risk in the business is a most important factor*, as well as the locality where the business is conducted, and *the rate expected and usually realized there upon investments of a somewhat similar nature with regard to the risk attending them*. . . . *The less risk, the less right to any unusual returns upon the investments.* One who invests his money in a business of a somewhat hazardous character is very properly held to have the right to a larger return, without legislative interference, than can be obtained from an investment in government bonds or other perfectly safe security. . . .]
> In an investment in a gas company, such as complainant's, the risk is reduced almost to a minimum. It is a corporation which . . monopolizes the gas service of the largest city in America, and is secure against competition under the circumstances in which it is placed . . An interest in such a business is as near a safe and secure investment as can be imagined with regard to any private manufacturing business . .

[2022] 320 U.S. at 603. Citations omitted.

These standards are established as a matter of constitutional law.[2023] As such, the *Bluefield* and *Hope* standards are controlling.[2024] Indeed, the balancing of the interests of the ratepayers and the utility's shareholders required by *Bluefield* and *Hope* have long been recognized by the Michigan Supreme Court. *See City of Detroit v. Michigan Public Service Commission,* 308 Mich 706, 14 N.W. 2d 784 (1944):

> It is the duty of the Commission, under its statutory power, to fix a just and reasonable rate. This can be accomplished only by balancing the interest of public utility investors and the consuming public. *Federal Power Commission v. Hope Natural Gas Co.*, . . .[2025]
>
> The public should not be required to pay rates that will yield an extraordinary profit to the utility and the stockholders of the utility on the other hand are at all times entitled to a fair return on their investment. . . .[2026]
>
> If the price of electricity can be reduced and still leave a reasonable return on the fair value of all property as required by [statute], then the commission has a duty to make such reduction in rates.[2027]

Similarly, the Commission has long recognized the applicability of the *Bluefield* and *Hope* standards. *See, e.g.*, Case No. U-5365, Opinion and Order, September 28, 1978, p. 24 ("The United States Supreme Court has established standards to measure the reasonableness of a rate of return on common equity established by a regulatory

---

[2023] *See, Bluefield*, *supra* at 690 ("The question in the case is whether the rates prescribed in the commission's order are confiscatory and therefore beyond legislative power. Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.").

[2024] See *Michigan Public Utilities Commission v. Michigan State Telephone*, 228 Mich 658, 664, 200 N.W. 749 (1924)("These elements [of just compensation, including . . a fair return upon the present value of the property used and useful in public service], when determined, measure the rate to be paid by the public for the service. Upon the issue of confiscation, a federal question, decisions of the Supreme Court of the United States are controlling.").

[2025] 308 Mich at 716.

[2026] 308 Mich at 718.

[2027] 308 Mich at 715 (Dissent).

commission", quoting *Bluefield* and *Hope*, *supra.*).[2028] In addition, Commission has noted that the determination of what is fair and reasonable "is not subject to mathematical computation with scientific exactitude but depends upon a comprehensive examination of all factors involved, having in mind the objective sought to be attained in its use."[2029]

The financial integrity of Consumers' business and its ability to maintain its credit and attract capital are directly a function of Consumers' lack of risk as a regulated utility. As S&P succinctly states, the regulated utility industry is "very low risk" as it "provides indispensable services that are strategically important to economies, have material barriers to entry, and essentially operate as a monopoly insulated from market challenges."[2030]

a. Consumers

Ms. Bulkley states that she estimated the market-based cost of equity by applying traditional estimation methodologies to a proxy group of comparable utilities, including the constant growth form of the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Empirical Capital Asset Pricing Model ("ECAPM"), and a Bond Yield Risk Premium ("BYRP" or "Risk Premium") analysis.[2031] She adds that her recommendation also takes into consideration the business and regulatory risk of Consumers relative to the proxy group, and Consumers' proposed

---

[2028] Citations omitted.
[2029] Case No. U-15244, Order, December 23, 2008, p. 12, citing *Meridian Twp. v City of East Lansing, Mich*., 342 Mich 734, 749, 71 NW2d 234 (1955).
[2030] This characterization of the low-risk nature of the regulated utility industry was expressly affirmed by the Commission in a recent finding. *See* Case No. U-20836, Order, November 18, 2022, p. 231, 241; PFD, September 19, 2022, p. 449-450, quoting 8 Tr 3065.
[2031] 4 Tr 2717.

capital structure as compared with the capital structures of the operating utilities of the proxy group companies.[2032] She asserts that while she did not make specific adjustments to her ROE recommendation for these factors, she considered them in the aggregate when determining where her recommended ROE falls within the range of the analytical results.[2033]

Ms. Bulkley stated that her analyses and recommendations considered that the United States ("U.S.") Supreme Court's ("Court") *Hope* and *Bluefield* decisions established the standards for determining a fair and reasonable authorized ROE for public utilities, including consistency of the allowed return with the returns of other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and the requirement that the result lead to just and reasonable rates.[2034] She adds that the results of several analytical approaches that provide estimates of Consumers' cost of equity, asserting that because Consumers' authorized ROE should be a forward-looking estimate over the period during which the rates will be in effect, her analyses rely on forward-looking inputs and assumptions (e.g., projected analyst growth rates in the DCF model, forecasted risk-free rate and market risk premium in the CAPM analysis).[2035] She states that although the companies in her proxy group are generally comparable to Consumers, each company is unique, and accordingly, she considered Consumers' regulatory, business, and financial risks relative to a proxy group of comparable companies in determining where Consumers'

[2032] Id.
[2033] Id.
[2034] 4 Tr 2718, citing *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").
[2035] 4 Tr 2719.

ROE should fall within the reasonable range of analytical results to appropriately account for any residual differences in risk.[2036]

Ms. Bulkley concludes that considering the analytical results of the market-based cost of equity models, current and prospective capital market conditions and Consumers' regulatory, business, and financial risk relative to the proxy group, an ROE in the range of 10.25% to 11.25% is reasonable.[2037]

Ms. Bulkley states that the Court's precedent-setting *Hope* and *Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's allowed ROE.[2038] She adds that among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) the principle that the result reached, as opposed to the methodology employed, is the controlling factor in arriving at just and reasonable rates.[2039] She states that the Commission has acknowledged that "[t]he criteria for establishing a fair ROR for public utilities is rooted in the language of the landmark United States Supreme Court cases *Bluefield* [and] *Hope*."[2040]

Ms. Bulkley states that utilities compete directly for capital with other investments of similar risk, which include other electric, natural gas, and water utilities nationally.[2041]

[2036] Id.
[2037] 4 Tr 2720.
[2038] Id.
[2039] Id.
[2040] 4 Tr 2720-2721, citing Case No. U-20963, Order, December 22, 2021, p. 221-222.
[2041] 4 Tr 2722.

She adds that an authorized ROE significantly below authorized ROEs for other utilities can inhibit the utility's ability to attract capital for investment.[2042]

Ms. Bulkley states that the Commission's order in this proceeding should establish rates that provide the Company with a reasonable opportunity to earn a ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises with similar risk.[2043] She asserts that It is important for the ROE authorized in this proceeding to take into consideration current and projected capital market conditions, and that because utility operations are capital-intensive, regulatory decisions should enable the utility to attract capital at reasonable terms under a variety of economic and financial market conditions.[2044]

Ms. Bulkley states that capital market conditions influence cost of equity models by affecting inputs in the model at the time the analysis is performed.[2045] She adds that it is important to consider projected market data to estimate the return of the forward-looking period.[2046]

Ms. Bulkley states that while core inflation has declined in response to the Federal Reserve's monetary policy, it continues to remain significantly above the Federal Reserve's target level of 2.00%.[2047]

Ms. Bulkley states that economists and analysts are expecting elevated yields on long-term government bonds, noting that in the most recent published Blue Chip

---

[2042] Id.
[2043] 4 Tr 2724.
[2044] 4 Tr 2724-2725.
[2045] 4 Tr 2725.
[2046] Id.
[2047] 4 Tr 2726.

Financial Forecasts report, economists projected the 30-year treasury rate to remain relatively stable and decrease only slightly from 4.60% in Q2/2025 to 4.40% in Q2/2026.[2048]

Ms. Bulkley states that financial markets have been extremely volatile since President Trump announced a significant set of tariffs on April 2, 2025.[2049] She adds that the high level of uncertainty associated with the economic effects of the Trump Administration's tariff policy has resulted in significant volatility increasing the risk of holding equity investments and implying an increase in the cost of equity.[2050]

Ms. Bulkley states that Consumers Energy currently has an investment-grade long-term rating of A- from S&P and A3 from Moody Investors Service's ("Moody's").[2051]

Ms. Bulkley states that it is necessary to establish a group of companies that is both publicly traded and comparable to Consumers in certain fundamental business and financial respects to serve as its "proxy" for purposes of estimating the cost of equity.[2052] She adds that the proxy companies used in her analyses all possess a set of operating and risk characteristics that are substantially comparable to Consumers, and thus provide a reasonable basis to estimate the appropriate cost of equity for Consumers.[2053]

Ms. Bulkley states that she began with the group of 36 companies that Value Line classifies as Electric Utilities and applied screening criteria to select companies that a) pay consistent quarterly cash dividends, b) have investment grade long-term issuer ratings; c) have positive long-term earnings growth forecasts from at least two

---

[2048] 4 Tr 2731. Citation omitted.
[2049] 4 Tr 2732.
[2050] Id.
[2051] 4 Tr 2734.
[2052] Id.
[2053] 4 Tr 2734-2735.

utility industry equity analysts; d) derive more than 40.00% of their megawatt-hour sales from their owned generation facilities and more than 60.00% of their total operating income from regulated electric operations; and e) were not parties to a merger or transformative transaction during the analytical periods relied on.[2054] She states that her proxy group includes 19 companies.[2055]

Ms. Bulkley states that the required cost of equity is estimated by using analytical techniques that rely on market-based data to quantify investor expectations regarding equity returns, adjusted for certain incremental costs and risks.[2056] She adds that informed judgment is then applied to determine where the company's cost of equity falls within the range of results produced by multiple analytical techniques.[2057] She states that the key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general, as well as the subject company (in the context of the proxy group), in particular.[2058]

Ms. Bulkley states that she considered the results of the constant growth form of the DCF model, the CAPM, the ECAPM, and a Bond Yield Risk Premium Analysis ("BYRP") analysis.[2059] She adds that in its order in Case No. U-21291 for DTE Gas Company, the Commission noted that the evidence that is presented by the parties in

---

[2054] 4 Tr 2735.
[2055] 4 Tr 2736; Ex. A-14, Sch. D-5.
[2056] 4 Tr 2737.
[2057] Id.
[2058] Id.
[2059] Id.

each case should be considered in determining the authorized return for the subject company.[2060]

Ms. Bulkley used the Constant Growth DCF model which assumes a) a constant growth rate for earnings and dividends; b) a stable dividend payout ratio; c) a constant price-to-earnings ratio; and d) a discount rate greater than the expected growth rate.[2061] She states that the average of her Constant Growth DCF results is 10.36%.[2062]

Ms. Bulkley states that she also made a CAPM analysis which estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or "systematic" risk of that security and a second component which is the product of the market risk premium and the beta coefficient, which measures the relative riskiness of the security being evaluated.[2063] In addition, she considered the results of an ECAPM in estimating the cost of equity for Consumers, which ECAPM she asserts addresses the tendency of the "traditional" CAPM to underestimate the cost of equity for companies with low beta coefficients such as regulated utilities.[2064] Her analyses resulted a CAPM range of 12.18% - 10.78% and an ECAPM range of 12.28% - 11.23%.[2065]

Ms. Bulkley states she performed a BYRP analysis which estimates the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds, using actual authorized returns for vertically integrated electric utilities as the

---

[2060] 4 Tr 2738-2739, quoting Case No. U-21291, Order, November 7, 2024, p. 106-107.
[2061] 4 Tr 2739.
[2062] 4 Tr 2742-2743; Ex. A-14, Sch. D-5.
[2063] 4 Tr 2743.
[2064] 4 Tr 2746-2747.
[2065] 4 Tr 2748; Ex. A-14, Sch. D-5.

historical measure of the cost of equity.[2066] She adds that investors are aware of authorized ROEs in other jurisdictions, which they consider as a benchmark for a reasonable level of equity returns for utilities of comparable risk operating in other jurisdictions.[2067] She states that her BYRP results averaged between 10.49% - 10.62%.[2068]

Ms. Bulkley states that the results of the cost of equity analyses alone do not provide an appropriate estimate of the cost of equity for Consumers, providing only a range of the appropriate estimate of Consumers' cost of equity, and that several additional factors impact the Company's overall risk profile relative to the proxy group and must be considered when determining where Consumers' cost of equity falls within the range of analytical results.[2069]

Ms. Bulkley states that flotation costs are the costs associated with the sale of new issues of common stock, and that to the extent that a company is denied the opportunity to recover prudently incurred flotation costs, actual returns will fall short of expected (or required) returns, thereby diluting equity share value.[2070] She adds that while the final ROE results do not incorporate an explicit adjustment for flotation costs, she considered the effect of flotation costs, along with the other risk factors present for Consumers, in determining where, within the range of analytical results, her recommended ROE for Consumers should fall.[2071]

[2066] Id.
[2067] 4 Tr 2749.
[2068] 4 Tr 2751; Ex. A-14, Sch. D-5, p. 22.
[2069] 4 Tr 2752.
[2070] Id.
[2071] 4 Tr 2756.

Ms. Bulkley asserts that Consumers' risk profile may be adversely affected in two related ways: a) the heightened level of investment increases the risk of under-recovery or delayed recovery of the invested capital; and b) an inadequate return would put downward pressure on key credit metrics.[2072] She states that Consumers Energy does currently have limited recovery of capital expenditures through the Renewable Energy Plan ("REP") and Power Supply Cost Recovery ("PSCR") that together allow for recovery of capital and operating costs associated with Consumers' compliance with its renewable portfolio standard.[2073] She notes that Consumers is requesting a Distribution Infrastructure Recovery Mechanism in this proceeding to recover a two-year period beginning May 1, 2026 consistent with the start of the test year.[2074] She asserts that if Consumers' proposed infrastructure mechanism is not approved, it is likely that other jurisdictions have more expansive cost recovery mechanisms.[2075]

Ms. Bulkley notes that In August 2024, RRA lowered its regulatory ranking of Michigan, stating in part:

> Regulatory Research Associates, a group within S&P Global Commodity Insights, views the regulatory climate in Michigan as somewhat constructive from an investor perspective. On July 31, 2024, RRA reduced its ranking of Michigan regulation to Average/1 from Above Average/3. While the jurisdiction remains more constructive than average from an investor viewpoint, the outcomes of certain recent rate proceedings could indicate a tightening in the regulatory climate.[2076]

Ms. Bulkley asserts that, based on her cost of equity analyses results, the qualitative analyses presented in her direct testimony, the business and financial risks

---

[2072] 4 Tr 2757.
[2073] 4 Tr 2759.
[2074] Id.
[2075] 4 Tr 2760.
[2076] 4 Tr 2766-2767, citing Regulatory Research Associates, Profile of Michigan Public Service Commission, accessed April 22, 2025.

of Consumers compared to the proxy group, and current and prospective conditions in capital markets, an ROE of 10.25% is reasonable and would fairly balance the interests of customers and shareholders.[2077]

b. Staff

Mr. Megginson states that Staff recommends a return on equity of 9.75%, which recommended ROE is the midpoint of its 9.25% - 10.25% ROE range.[2078] He adds that to aid in the determination of a fair ROE, since Consumers is not publicly traded, a group of eight publicly traded electric and/or gas-electric utility companies were used as a comparable proxy to Consumers.[2079] He states that the proxy group's data was used in the traditional Discounted Cash Flow (DCF) and Capital Asset Pricing Model (CAPM) return on equity estimates.[2080] He adds that he also used a Bond Yield + Risk Premium analysis and reviewed electric ROE authorizations from other state jurisdictions from 2021- June 2025.[2081]

Mr. Megginson states that Standard & Poor's (S&P) rates Consumers' senior secured debt "A", which was raised from "A-" on December 4, 2014; Moody's rates Consumers' senior secured debt "A1", which was lowered from "Aa3" in May 2021; and Fitch rates Consumers' senior secured debt "A+", which was raised two notches from "A-" in March 2016.[2082] He adds that S&P has held Consumers' credit rating steady for approximately 10 years and Fitch has held it steady for over eight years, while Moody's

---

[2077] 4 Tr 2768.
[2078] 6 Tr 4523
[2079] Id.
[2080] Id.
[2081] 6 Tr 4523-4524.
[2082] 6 Tr 4524.

one notch downward revision from Aa3 (equivalent to S&P's AA- rating) in 2021 put the Consumers' credit rating more in line with the other two agencies ratings.[2083]

Mr. Megginson states that in S&P's August 2024 report, the agency stated

> "We believe Michigan's regulatory construct as above average compared to peers because of the benefit of a streamlined 10-month rate case process. Other constructive rate mechanisms include the use of forward test-years, power supply cost rider adjustments, and natural gas cost rider adjustments. These mechanisms help the company earn its allowed ROE and minimize regulatory lag.[2084]

He adds that in Moody's May 29, 2025, ratings report, the agency stated:

> Consumers Energy is regulated in Michigan by the MPSC and we view the regulatory framework in Michigan to be more credit supportive than most other states. As a result of the 2008 and 2016 energy legislation in Michigan, the regulatory framework has been streamlined, improving both the rate case process and the timeliness of cost recovery.[2085]

He states that Fitch's May 30, 2025 credit assessment noted

> Fitch believes the (regulatory) framework remains constructive from a credit perspective, allowing for full pass-through of fuel costs and purchased power, forward-looking test years and a timely 10-month rate case resolution.[2086]

Thus, he asserts that the credit rating agencies acknowledge that Consumers currently has a stable foundation for its credit rating, and that Michigan has a very equitable regulatory environment that is supportive of a utility's ongoing business and financial health.[2087]

Mr. Megginson states that Consumers' net income has not only risen over the years but has risen rather substantially, with Consumers experiencing lower earnings in

---

[2083] 6 Tr 4524-4525.
[2084] 6 Tr 4525, citing S&P Global – Ratings Direct (Aug. 20, 2024).
[2085] Id., citing Moody's Investor Services – Credit Opinion (29, May 2025).
[2086] 6 Tr 4525-4526.
[2087] 6 Tr 4526.

only two of the past fifteen years.[2088] He asserts that this has enabled Consumers to access credit markets to the tune of billions in short and long-term financing at very competitive rates.[2089] He adds that Consumers issued $700 million of secured debt in July 2024 at a very favorable rate and credit spread, which he asserts shows that Consumers' ability to secure low to moderately priced debt has not been negatively impacted, even with the Moody's revision in 2021.[2090] He states that Consumers anticipates around $2.5 billion in long-term debt issuance in this case alone, which he argues does not suggest an inability or unwillingness to borrow.[2091]

Mr. Megginson states that Consumers has regulatory policies or provisions in place that can positively impact its credit rating, including the standard power supply cost recovery mechanism and Energy Waste and a Renewable Energy mechanism.[2092] He adds that Consumers can also recover certain distribution spending through its investment recovery mechanism (IRM) with surcharge authority, with respect which Consumers is requesting to increase the capacity and provisions within the approved IRM which if approved will further insulate Consumers from financial risk.[2093] He states that Consumers has also requested additional storm damage and service restoration provisions, which are designed to provide direct funding and preferable accounting for future exceptional weather events, which programs also have the benefit of improving

[2088] 6 Tr 4526-4527.
[2089] 6 Tr 4527.
[2090] Id.
[2091] 6 Tr 4527-4528; Ex. A-28.
[2092] 6 Tr 4528.
[2093] Id.

Consumers' cash flow and minimizing its financial risk.[2094] He asserts that this risk reduction should entail a modest reduction in Consumers' required ROE.[2095]

Regarding Consumers' reliance on its funds from operations to debt ratio (FFO-to-Debt) metric, Mr. Megginson states that S&P, in its most recent August 2024 ratings snapshot, noted "We expect [Consumers] will maintain stand-alone financial measures consistent with the middle of the range for its financial risk profile category, specifically FFO to debt of about 17%-19%."[2096] He adds that S&P notes that its rating could be negatively impacted if Consumers FFO-to-Debt ratio fell consistently below 15%, but that S&P anticipates above threshold FFO-to-Debt ratios for Consumers in the foreseeable future.[2097] He states that Moody's, in its May 2025 rating's report, noted "We expect the utility to maintain a relatively stable financial profile with cash flow from operations before changes in working capital, its CFO pre-WC to debt (Moody's FFO-to-Debt term) averaging around 19 -21% over the next 2-3 years."[2098] He adds that Fitch, in its May 2025 credit opinion, noted that "Fitch forecasts Consumers Energy's funds from operations (FFO) leverage to average at its 4.5x threshold in the near term and then improve to 4.2x through 2029, with Fitch noting that FFO leverage that exceeds 4.5x on a sustained basis, could lead to a negative ratings action.[2099] Thus, he asserts that Fitch does not forecast any rating decline concern with Consumers in the immediate future.[2100]

[2094] Id.
[2095] Id.
[2096] 6 Tr 4528-4529.
[2097] 6 Tr 4529.
[2098] Id.
[2099] Id.
[2100] Id.

Mr. Megginson states that when considering a return on equity recommendation for a utility company, Staff considers the legal guidelines from the landmark rulings of *Hope* and *Bluefield*.[2101]

Mr. Megginson states that no one methodology provides an exact measure of a fair rate of return on equity, but some methods provide good estimates.[2102] He adds that the DCF model and the CAPM are the primary models most utility financial analysts use in rate cases to determine a fair and reasonable cost of equity for regulated utility companies.[2103]

Mr. Megginson used six criteria in selecting a proxy group of comparable utility companies used in his ROE analysis, coming up with a group of eight electric utility companies.[2104] He adds that all the companies in his proxy group are part of Consumers 19 utility proxy group but asserts that although Staff does not agree with many of Consumers' proxy group members, the different groups are not the primary reason for their differing ROE recommendations.[2105]

Mr. Megginson states that his proxy group's average S&P credit rating is (BBB+), which is two notches below Consumers credit rating of (A), and that Moody's average credit rating for the group is (Baa1), which is three notches below Consumers credit

---

[2101] 6 Tr 4538, citing *Bluefield Water Works and Improvement Co. vs. Public Service Commission*, 262 U.S. 679, 692-693 (1923) and *Federal Power Commission vs. Hope Natural Gas Company*, 320 U.S. 591, 603 (1944).
[2102] 6 Tr 4539.
[2103] Id.
[2104] 6 Tr 4539-4540; Ex. S-4, Sch. D-5.
[2105] 6 Tr 4540.

rating of (A1).[2106] He asserts that Consumers has a much higher credit rating and is considered a better credit risk, i.e., safer company than the proxy group.[2107] He states that Consumers dividends out to its parent company 80% of its net income compared to the proxy group's 68% payout ratio.[2108] He notes that the average authorized ROE is 9.48%, which ROE is considerably less than Consumers' current 9.90% authorized ROE and substantially less than Staff's 9.75% ROE recommendation.[2109] He adds that the average equity layer for the electric proxy group is 51.07%, which equity layer is primarily due to one outlier equity layer, OGE Energy, with an equity layer well over 53.0%, and that removing that firm, the proxy group's average equity layer would be roughly 50.0%, which is in line with Staff's recommendation.[2110]

Mr. Megginson's DCF analysis resulted in an average DCF cost of equity estimate of 9.76%.[2111] For that analysis, he used June 1, 2025, through August 1, 2025, closing stock prices and annualized the current quarterly paid dividends to calculate dividend yields, which were then modified by the semi-annual compounding method.[2112]

For his CAPM analysis, Mr. Megginson used a historical risk premium and two projected market risk premiums.[2113] Combining the average risk-free rate of 4.58% with the calculated historical risk premium of 6.94% and the electric group's beta in the CAPM formula, he computed an average CAPM cost of equity of 10.05% for the

---

[2106] Id.; Ex. S-4, Sch. D-5.
[2107] 6 Tr 4540-4541.
[2108] 6 Tr 4541.
[2109] Id.
[2110] Id.
[2111] 6 Tr 4543; Ex. S-4, Sch. D-5, p. 5.
[2112] 6 Tr 4542.
[2113] 6 Tr 4544.

historical period.[2114] He adds that to account for the forward-looking nature of the CAPM, he conducted a projected CAPM analysis using forward-looking market risk premium estimates. Combining the average risk-free rate of 4.58% with the projected risk premia of 4.15% and 5.66% and the electric group's betas, he computed two CAPM ROE estimates of 7.85% and 9.04%, noting that the 12-month cash yield analysis produces an unreasonably low ROE estimate.[2115]

Mr. Megginson states that his bond yield + risk premium approach incorporates the spread from historical electric utility realized stock returns and historical composite utility bond yields and adds this spread to the projected yield on an A-rated long-term utility bond.[2116] He adds that he also incorporated a historical Treasury Bond analysis to estimate an additional bond yield + risk premium ROE estimate.[2117] He states that adding the projected bond yield to the historical market risk premium of 4.56% produces an ROE estimate of 10.23%, and that adding the historical Treasury Bond spread of 5.88% to the projected 30-year T-bond yield of 4.58%, produces an ROE estimate of 10.46%.[2118]

Mr. Megginson states that he reviewed the authorized rate of return decisions for electric utilities rendered by other state commissions across the country from 2021 through June 2025, adding that the average authorized ROE decision for 2021 was 9.38%, for 2022 was 9.54%, for 2023 was 9.60%, for 2024 was 9.74%, and through

---

[2114] 6 Tr 4545.
[2115] 6 Tr 4546.
[2116] 6 Tr 4547.
[2117] Id.
[2118] 6 Tr 4548; Ex. S-4, Sch. D-5.

June of 2025 was 9.68%.[2119] The full four-year average ROE (2021-2024) is 9.57%, which is well below the 9.90% ROE that Consumers has been routinely authorized over that same period, and well below Staff's ROE recommendation of 9.75% in this case.[2120]

Mr. Megginson states that Staff's position that a cost of equity recommendation for Consumers Energy's Electric division falls within the range of 9.25% - 10.25%, and thus, Staff recommends an ROE of 9.75%.[2121] He adds that according to data provided by Consumers, for every 1 basis points change in the ROE, the difference is $888,000 per basis point, such that if the Commission were to adopt Consumers' 10.25% ROE as opposed to Staff's 9.75% recommendation, it would cost ratepayers an additional $44.4 million annually.[2122]

Mr. Megginson states that he agrees with Consumers DCF analysis in general but asserts that some of the growth rates are elevated and unduly boost the ROE.[2123] Regarding Consumers' Projected CAPM analyses, he states that Consumers' market risk premium results are substantially higher than the historical market risk premium of around 7.0%, which produce overstated and clearly unreasonable results in the 11.50% range.[2124]

Regarding ECAPM, Mr. Megginson disagrees with the ECAPM approach in general because ECAPM was established using raw betas and short-term debt metrics,

---

[2119] Id., Ex. S-4, Sch. D-5, p. 13.
[2120] Id.
[2121] 6 Tr 4549; Ex. S-4, Sch. D-5, p. 14.
[2122] 6 Tr 4550.
[2123] 6 Tr 4550-4551.
[2124] 6 Tr 4552.

while Consumers' ECAPM analysis uses Value Line and Bloomberg adjusted betas and long-term debt metrics, which change in input renders the need for the ECAPM adjustment unnecessary.[2125] He asserts that using adjusted betas in the ECAPM analysis is tantamount to double counting the beta and improperly inflating the ROE estimate.[2126]

Regarding Consumers' Bond Yield + Risk Premium (BYRP) analysis, Mr. Megginson states that methodology for its BYRP analysis is rather complicated and circular, and that Consumers doesn't use the average risk premium result they calculated in their BYRP analysis but uses an inflated result instead.[2127]

Mr. Megginson asserts that flotation cost enhancement to any of Consumers' ROE estimates should be rejected.[2128] He argues that Consumers Energy, as a subsidiary of its parent company CMS Energy, does not issue its own stock and thus does not incur flotation costs, and therefore, it would be improper to include flotation cost enhancement to any of Consumers' cost of equity models.[2129]

Mr. Megginson argues that the Commission should reject Consumers' 10.25% ROE recommendation for several reasons, including the request also does not coincide with Consumers' solid credit rating and the Commission's approval of many of Consumers' preferred enhancement programs and Consumers' request to further enhance those programs in this rate case, which if approved, ensures recovery of costs

---

[2125] 6 Tr 4553.
[2126] 6 Tr 4554.
[2127] 6 Tr 4555.
[2128] 6 Tr 4556.
[2129] Id.

associated with those programs and thus reduces Consumers' overall business and financial risk.[2130] He adds that Consumers' practice of filing a new rate case no more than 12 months after its prior rate case, even with cases that include a test-year that won't terminate until several months after the filing of this new rate case, borders on a 100% risk-free investment for the company.[2131] He asserts that this tremendous risk reduction calls for an ROE dramatically less than Consumers' 10.25% request and much less than currently authorized 9.90% ROE.[2132]

c. Attorney General

Mr. Coppola states that a utility company is entitled to a fair return that will allow it to attract capital and be sufficient to assure investors of its financial soundness, and cites *Bluefield* and *Hope*.[2133] Mr. Coppola states that he used the Discounted Cash Flow (DCF) Method, the Capital Asset Pricing Model (CAPM), and the Utility Risk Premium approach to determine the cost of common equity.[2134] He adds that while the three methodologies result in an average ROE of 9.73%, he recommends an allowed ROE of 9.80%.[2135]

Mr. Coppola developed a proxy group of eleven companies, all of which have growing earnings and dividends.[2136] He adds that Consumers' peer group contains eight of the companies in his peer group.[2137] He asserts that the other companies included in

---

[2130] 6 Tr 4556.
[2131] 6 Tr 4557.
[2132] Id.
[2133] 3 Tr 2536-2537.
[2134] 3 Tr 2537
[2135] Id.; Ex. AG-36.
[2136] 3 Tr 2538; Ex. AG-42.
[2137] 3 Tr 2539.

Consumers' proxy group should be removed due to excessively large sizes, non-utility businesses, sale and merger activity, and poor earnings history and inconsistent earnings growth rates.[2138] He concludes that Consumers' proposed proxy group includes companies that are not comparable to Consumers and should not be relied on in determining an appropriate cost of equity capital in this rate case.[2139]

For his DCF analysis, Mr. Coppola states that he used an average dividend yield of 3.56% and an average EPS growth rate of 6.01%, resulting in an average DCF ROE of 9.57%.[2140] He adds that because the DCF analysis relies upon financial market information for the dividend yield judgments of dividend and earnings growth prospects of security analysts which reflects the consensus of the market on which investors rely, he places a fairly high degree of reliability in the DCF results when considered in conjunction with the results of other methods in determining the cost of common equity.[2141]

Mr. Coppola states that Ms. Bulkley calculated a DCF cost of equity capital of 10.24%, which is 67 basis points higher than the 9.57% DCF result he calculated.[2142] He notes that the dividend yield in my analysis is 3.56%, while Consumers calculated a higher yield of 3.75%.[2143] He adds that Consumers projected growth rate is higher at 6.48% vs. 6.01% in his analysis.[2144] He states that the data on the dividend yield and the earnings growth rates used by Consumers were compiled sometime earlier in 2025

[2138] Id.
[2139] Id.
[2140] 3 Tr 2540-2541; Ex. AG-37.
[2141] 3 Tr 2541.
[2142] Id. Citation omitted.
[2143] Id.
[2144] 3 Tr 2542.

and are now stale, and that the stock prices of the utilities in the peer group are now higher, thereby justifying a lower dividend yield compared to Consumers' filed case.[2145]

Regarding his CAPM analysis, Mr. Coppola states that this measure of risk – Beta -- reflects the extent to which the price of a particular security varies in relationship to the movement of the overall market, with securities that vary over time more than the overall market will have a Beta that is greater than 1.00, while some securities vary less in price over time than the overall market, with the Beta will be less than 1.00.[2146] He states that utility stocks tend to move less than the overall market, and thus, the average Beta of his peer group is 0.76.[2147] The results of his CAPM method is 9.98%, which is based on a 4.40% risk-free rate; the Betas of the companies in the Peer Group taken from Value Line; and the 7.35% historical Market Risk Premium return from the years 1926 to 2024.[2148] He adds that, because the key issue with CAPM is that it assumes that the entire risk to the investor is from fluctuations in the overall market, when in actuality, investors take into consideration company-specific factors in assessing the risk of each particular security, he gives the CAPM approach less weight than the DCF approach in determining the cost of common equity.[2149]

Regarding Consumers' CAPM analysis, Mr. Coppola states that Consumers' use of the 4.30% 30-year forecasted U.S. Treasury bond rate is flawed because it reflects U.S. Treasury rates forecasts for 2026 to 2030, which in large part includes periods

---

[2145] Id.
[2146] 3 Tr 2543.
[2147] Id.
[2148] 3 Tr 2544; Ex. AG-38. Citation omitted.
[2149] Id.

beyond the test year ending October 6, 2026.[2150] He adds that instead of using a proven historical market risk premium (MRP), Consumers developed its MRP based largely on future expected stock price growth rates and dividends for a select group of companies from the S&P 500 stock index over the next three to five years, based on her sample of companies, Ms. Bulkley calculating a forecasted stock market return of 12.58%.[2151] In that regard, he notes that when witness Bulkley conducted her analysis of projected market returns in case U-21806 earlier in 2025, her expected market return was 12.04%, or 50 basis points less than in this case, which substantial swing in the stock market return over a short timeframe calls into question placing much reliance on this projected MRP methodology.[2152] He also notes that Consumers' approach in developing a projected MRP is problematic as 125 companies or 25% of the named companies in the list of S&P 500 Index with dividend yields and long-term growth estimates are omitted, and that many large technology companies with high growth prospects have a larger than normal weighting in the calculation of the 12.58% return due to their relatively large market capitalization**.**[2153]

Mr. Coppola states that Ms. Bulkley using an extremely short period of 3 to 5 years to measure stock market returns in determining the MRP, which does not include a complete cycle of economic expansion and contraction, which is what occurs over the long-term.[2154] He asserts that Consumers' approach is akin to only selecting the positive return years over the 98-year historical period of stock market returns and not the

---

[2150] 3 Tr 2546.
[2151] Id.
[2152] 3 Tr 2546-2547.
[2153] 3 Tr 2547.
[2154] Id.

losses in the downturn years.[2155] He states that Roger Morin supports the use of the longest possible period for calculating a market risk premium, as follows:

> Therefore, an historical risk premium study should consider the longest possible period for which data are available. Short-run periods during which investors earn a lower risk premium than they expect are offset by short-run periods during which investors earn a higher risk premium than they expect. Only over long time periods will investor return expectations and realizations converge. Clearly, the accuracy of the realized risk premium as an estimator of the prospective risk premium is enhanced by increasing the number of years used to estimate it.[2156]

Regarding Ms. Bulkley's use of the ECAPM method, Mr. Coppola states that the basic premise for the use of the ECAPM method -- that the Beta factors published by Value Line when used in CAPM analysis do not accurately predict stock performance -- is flawed.[2157] He asserts that The ECAPM produces a faulty cost of equity rate with a bias toward overstating and inflating the true cost of equity capital, and thus the Commission should continue to disregard this alternative approach to the traditional CAPM method.[2158]

Mr. Coppola also used a utility risk premium approach to estimating an ROE, which involves projecting the cost of debt for the peer group and adding to this cost the average return differential of utility common stocks over utility bonds.[2159] Using the projected average rate for utility bonds rated "A", which is the projected 30-year U.S. Treasury bond rate plus (b) the average spread of 1.16% for 30-year "A" rated utility bonds issued in 2024 compared to U.S. Treasury bonds and adding the historical rate of

---

[2155] Id.
[2156] 3 Tr 2548. Citation omitted.
[2157] 3 Tr 2548.
[2158] 3 Tr 2549.
[2159] 3 Tr 2551.

electric utility stock returns versus “A” rated debt yields from 1936 to the present, he calculated a Risk Premium return rate of 9.81%.[2160]

Mr. Coppola states that instead of providing a traditional utility risk premium analysis, Ms. Bulkley uses an unorthodox approach she refers to as Bond Yield Risk Premium (BYRP), whereby she compared authorized ROEs from electric utility rate case decisions from 1980 to early 2025 to the 30-year U.S. bond yields to calculate an average risk premium, which was added the 30-year U.S. bond yield for the projected test year to arrive at a 10.56% ROE rate.[2161] Mr. Coppola asserts that there are three major flaws with this methodology: a) it lacks any comparison of actual utility returns achieved from price appreciation and dividends to bond yields, b) the analysis is biased because it covers a period when interest rates were declining from 12.1% in late 1980 to 4.2% in 2024; and c) the analysis assumes a direct relationship between declining interest rates and ROE decisions as happening almost instantaneously monthly, contrary to the concept of gradualism in reducing or increasing ROEs that are not in lock step with interest rate changes.[2162]

Mr. Coppola notes that for the ROEs granted by state regulatory commissions for U.S. electric utilities during the two years ending in June 2025, the majority of the 50 ROE decisions in the year ended June 2024 and the 46 decisions in the year ended June 2025 are at rates well below 9.90%.[2163] He states that only ten decisions in the year ending June 2024 and fourteen decisions in 16 year ended June 2025 were at rates of 9.90% or greater, with these higher rates being primarily from regulatory

[2160] Id.; Ex. AG-39.
[2161] 3 Tr 2551-2552; Ex. A-14, p. 22.
[2162] 3 Tr 2552-2553. Citation omitted.
[2163] 3 Tr 2554; Ex. AG-40.

commissions in California (with wild fires and earthquakes), Florida (with hurricanes), and Michigan, or pertain to small companies or unique geographical challenges, such as in Alaska.[2164] He adds that for most of the other electric utilities that have business and financial risks comparable to Consumers' operations, the ROE rates have averaged around 9.5% to 9.6% in the past two years, which he asserts suggests that Consumers' current ROE rate of 9.90% is excessive and "out of line" with comparable electric utilities.[2165] He also notes that the average ROE rate during the two years ended June 2025 for the utilities in his peer group is 9.57%.[2166]

Mr. Coppola states that the Commission should not be concerned that authorizing an ROE below 9.9% will lead to impairment of Consumers' ability to access the capital market.[2167] He states that any such concerns are not supported by the evidence, adding that several electric utilities that have accessed the capital markets at competitive interest rates since receiving ROEs near or below the average rate of 9.50%.[2168] He asserts that there is no evidence that equity investors have abandoned utilities that have been granted ROEs near or below the industry average, and that stock investors continue to migrate to utility stocks.[2169] Noting that the average market to book ratios for each of the peer group companies is approximately 2.0 times, he states that many of these companies have received rate orders during the past few years reflecting ROEs as low as 8.63%.[2170] He adds that the fact that Consumers needs

---

[2164] 3 Tr 2554-2555
[2165] 3 Tr 2555.
[2166] Id.; Ex. AG-41.
[2167] 3 Tr 2559.
[2168] Id.; Ex. AG-40.
[2169] 3 Tr 2559-2560; Ex. AG-43.
[2170] Id.

to raise capital because of a large capital investment program to upgrade its infrastructure and for other purposes is not unique to Consumers, as most electric utilities face the same issues and are able to raise capital with ROEs at or near the 9.5% average rate.[2171]

Mr. Coppola states that stock market volatility should not be a concern in establishing a fair ROE rate, as volatility is not risk.[2172] He states that utility stocks are a safe-haven for investors during times of uncertainty and volatility because they are not as susceptible to volatility as the general stock market, and that this is reflected in the average Beta value of 0.76 of the utility peer group in contrast with the general stock market value of 1.0.[2173]

Mr. Coppola states that the market for new utility debt issues has been very robust with over 400 new issues completed in 2023 and 2024, and with many utility companies having issued new debt shortly after receiving a rate order with ROEs below 9.50%.[2174] He adds that so far in 2025, Consumers has issued $1.125 billion of new long-term debt at rates of 4.5% (5.5 years to maturity) and 5.05% (10 years to maturity), issued $700 million of long-term debt in July 2024 at an interest rate of 4.7% and a 5-year 4 term, and in January of 2024, issued $600 million of new 10-year debt at an interest rate of 4.6%.[2175] He states that CMS Energy has also come to market and issued $1.0 billion of new 30-year debt at a rate of 6.5%.[2176]

[2171] 3 Tr 2560.
[2172] 3 Tr 2561-2562, citing Ex. AG-51.
[2173] 3 Tr 2562.
[2174] Id.; Ex. A-28; Ex. AG-40.
[2175] 3 Tr 2563.
[2176] Id.

d. ABATE

Mr. Walters states that authorized ROEs for both electric and gas utilities have declined over the last 10 years and have been below 10.0% for about the last nine years.[2177] He adds that utilities have been able to access external capital to support capital expenditure programs. He states that capital expenditures for the regulated electric and natural gas delivery utilities have increased considerably over the period 2023 into 2024, and the forecasted capital expenditures remain elevated through the end of 2026.[2178] He asserts that capital investments for the utility industry continue to stay at elevated levels, and these capital expenditures are expected to fuel utilities' profit growth into the foreseeable future.[2179] This is clear evidence that these capital investments are enhancing shareholder value and are attracting both equity and debt capital to the utility industry in a manner that allows for funding these elevated capital investments.[2180] He argues that while capital markets embrace these profit-driven capital investments, regulatory commissions also must be careful to maintain reasonable prices and tariff terms and conditions to protect customers' need for reliable utility service at reasonable rates, such that if this is not done, utility rates will expand beyond the ability of customers to pay, resulting in revenue constraints for utilities, which will impact their financial integrity.[2181]

Mr. Walters states that the historical valuation of utilities followed by The Value Line Investment Survey ("Value Line"), indicates utility security valuations today are very

---

[2177] 6 Tr 3747; 3749, Figure CCW-1; 3749.
[2178] 6 Tr 3752, Figure CCW-2.
[2179] Id.
[2180] Id.
[2181] 6 Tr 3752-3753.

strong and robust relative to the last several years, which are indicate that utilities have access to equity capital under reasonable terms and at lower costs.[2182] He adds that generally, authorized ROEs, credit standing, and access to capital have been quite robust for utilities over the last several years, even throughout the duration of the global pandemic, and asserts that it is critical that this Commission ensure that utility rates are increased no more than necessary to provide fair compensation and maintain financial integrity.[2183]

Mr. Walters states that the federal funds rate has risen more rapidly than utility and Treasury bond yields, while the yield spread between utility bonds and Treasury bonds has narrowed and is currently below its long-term average.[2184] He asserts that this narrower spread suggests that investors perceive lower relative risk in utility bonds compared to Treasuries, requiring less additional yield to hold them, which trend typically reflects greater confidence in the financial stability and creditworthiness of utilities, driven by factors such as stable earnings, favorable regulatory environments, or improved credit fundamentals.[2185]

Mr. Walters states that independent economists, surveyed by Blue Chip Financial Forecasts, expect long-term bond yields to remain relatively flat to marginally increase over the near term, while maintaining levels that are still relatively low by historical levels.[2186] He adds that S&P views affordability as a cornerstone issue for the sector: sustained rate increases or cost shifts that threaten affordability could erode regulatory

---

[2182] 6 Tr 3753; Ex. AB-5.
[2183] Id.
[2184] 6 Tr 3755, Figure CCW-3..
[2185] 6 Tr 3755-3756.
[2186] 6 Tr 3757-3758, Table CCW-3..

support, triggering credit risk, such that the Commission should prioritize bill affordability when analyzing risks Consumers faces.[2187] He states that In a July 2025 update, S&P noted that 84% of the investment grade issuers had either a stable or positive outlook, and reported that credit rating upgrades have outpaced rating downgrades year-to-date.[2188]

Mr. Walters states that since 2020, Consumers has received approximately $518.1 million in rate increases over five rate cases, and that if the proposed increase in this case ($460.2 million) is granted, it would mean that in a little more than five years, Consumers will have received nearly $1 billion in base rate revenue increases.[2189]

Mr. Walters states that since the beginning of the second half of 2021, and despite the risks from higher levels of inflation, expectations of higher interest rates, and geopolitical events around the world, the electric utility sector has largely tracked the S&P 500, with a total return of 57.47% compared to the market's total return of 63.13%.[2190] He notes that the S&P 500's strong performance in 2023 and early 2024 was largely driven by a small group of "mega-cap" companies known as the Magnificent 7, which seven stocks accounted for a majority of the S&P 500's returns even though there were 493 other companies in the index.[2191] He adds that while the S&P 500's strong performance in 2023 and early 2024 was largely driven by a small group of "mega-cap" technology companies, the utility sector demonstrated positive and

---

[2187] 6 Tr 3761.
[2188] Id., citing S&P Global Credit Ratings, "Industry Credit Outlook Update – North America Regulated Utilities," July 16, 2025.
[2189] 6 Tr 3763.
[2190] 6 Tr 3764, Figure CCW-4.
[2191] 6 Tr 3764-3765. Citation omitted.

relatively stable returns over this period.[2192] He asserts that this reflects the defensive characteristics of regulated utilities, which are often viewed by investors as safer assets during times of macroeconomic and geopolitical uncertainty, due to utilities' essential service nature, predictable cash flows, and supportive regulatory environments.[2193]

Mr. Walters states that determining a fair cost of common equity for a regulated utility has been framed by two decisions of the U.S. Supreme Court, *Bluefield* and *Hope*.[2194] He adds that the Supreme Court found that a utility is entitled to such rates as would permit it to earn a return on a property devoted to the convenience of the public that is generally consistent with the same returns available in other investments of corresponding risk, and that the utility has "no constitutional rights to profits" such as those "realized or anticipated in highly profitable enterprises or speculative ventures."[2195] He states that a fair rate of return (ROR) is based on the expectation that the utility's costs reflect efficient and economical management, and the return will support its credit standing and access to capital, but the return will not be in excess of this level.[2196]

Mr. Walters states that to estimate an ROE for Consumers, he assessed the market's perspective of Consumers Energy's risk, developed a proxy group of publicly traded utility companies that have similar risks and characteristics to Consumers, and performed the following models: (1) a constant growth Discounted Cash Flow ("DCF") model using consensus analysts' growth rate projections; (2) a constant growth DCF

[2192] 6 Tr 3765.
[2193] Id.
[2194] 6 Tr 3768. Citations omitted.
[2195] Id.
[2196] 6 Tr 3769.

model using sustainable growth rate estimates; (3) a multi-stage growth DCF model; (4) a Risk Premium method; and (5) a Capital Asset Pricing Model ("CAPM").[2197]

Mr. Walters states that the market's assessment of a company's investment risk is generally described by credit rating analysts' reports, and that the current credit ratings for Consumers Energy is A- from S&P and A3 from Moody's.[2198] Mr. Walters quotes from S&P's September 2025 report on Consumers, in part, as follows:

> The stable rating outlook on CE reflects our expectation that management will focus on its core utility operations and reach constructive regulatory outcomes to avoid increasing business risk. We expect CE will maintain stand-alone financial measures consistent with the middle of the range for its financial risk profile category, specifically FFO to debt of 17%-20%.
>
> We expect Consumers Energy Co. (CE) to continue to effectively manage its regulatory risk. We believe Michigan's regulatory construct is above average compared with peers because of the benefit of a streamlined 10-month rate case process. Other constructive rate mechanisms include the use of forward test-years, power supply cost rider adjustments, and natural gas cost rider adjustments. These mechanisms help the company earn its allowed return on equity (ROE) and minimize regulatory lag.[2199]

Mr. Walters states that he started with the same utility company proxy group relied on by Ms. Bulkley and then removed two companies due to merger activity, resulting in 17 companies in his proxy group.[2200] He adds that the proxy group has average credit ratings of BBB+ and Baa2 from S&P and Moody's, respectively, with the proxy group's average rating of BBB+ from S&P being one notch lower than

---

[2197] 6 Tr 3769.
[2198] 6 Tr 3771, citing S&P Capital IQ, accessed on September 12, 2025.
[2199] 6 Tr 3771-3772, citing S&P Capital IQ RatingsDirect, "Full Analysis | Consumers Energy Co," September 15, 2025.
[2200] 3773; Ex. AB-6.

Consumers' rating of A- from S&P and the proxy group's average rating of Baa2 from Moody's is two notches lower than Consumers' rating of A3 from Moody's.[2201]

Mr. Walters states that he applied a constant growth DCF model, using the average of the weekly high and low stock prices of the utilities in the 13 proxy group over a 13-week period ending on September 12, 2025, each proxy company's most recently paid quarterly dividend as reported in Value Line, and dividend growth rates from Zacks, S&P Capital IQ Market Intelligence ("MI"), and Institutional Brokers' Estimate System ("I/B/E/S") from LSEG Workspace.[2202] He adds that the average growth rate for my proxy group is 7.22% and a median growth rate is 6.87%, resulting in the average and median constant growth DCF returns for my proxy group for the 13-week analysis are 11.05% and 10.50%, respectively.[2203] He notes that the constant growth DCF analysis is based on a group average long-term growth rate of 7.22%, which three- to five-year growth rates are approximately 77% higher than the long-term projected GDP growth rate of 4.09%.[2204] He states that the long-term maximum sustainable growth rate for a utility investment is limited by the projected long-term GDP growth rate, as that reflects the projected long-term growth rate of the economy, and that the consensus projection for U.S. GDP, as published by Blue Chip Financial Forecasts, is an annual growth rate of approximately 4.09% over the next 10 years.[2205]

Mr. Walters states that the sustainable growth DCF model is linked to the percentage of earnings retained within a company, as opposed to being paid out as

---

[2201] 6 Tr 3773-3774.
[2202] 6 Tr 3775-3777.
[2203] 6 Tr 3777; Ex. AB-8.
[2204] Id.
[2205] 6 Tr 3777-3778.

dividends.[2206] He adds that the average and median sustainable growth rates for the proxy group using this internal growth rate model are 5.29% and 4.83%, respectively, and that a sustainable growth DCF analysis produces proxy group average and median DCF results for the 13-week period of 9.05% and 8.85%, respectively.[2207]

Mr. Walters states that to accommodate changing growth expectations, he conducted a multi-stage DCF analysis that reflects growth rate change over time.[2208] He adds that the multi-stage DCF model reflects three growth periods: (1) a short-term growth period consisting of the first five years; (2) a transition period, consisting of the next five years (6 through 10); and (3) a long-term growth period starting in year 11 and extending into perpetuity.[2209] He states that the U.S. GDP nominal growth rate is a conservative proxy for the highest sustainable long-term growth rate of a utility.[2210] He adds that the real GDP and nominal GDP growth projections made by other independent sources support his use of 4.09% as a reasonable estimate of market participants' expectations for long-term GDP growth.[2211] He states that the average and median multi-stage DCF ROEs for my proxy group using the 13-week average stock price are 8.62% and 8.21%, respectively.[2212] He adds that the results of the constant growth DCF using analysts' growth rates assume an average long-term growth rate which is higher than the long-term projected GDP growth rate, which is an unsustainable assumption which likely leads to an overstatement in the cost of equity

---

[2206] 6 Tr 3778.
[2207] 6 Tr 3779; Ex. AB-10, Ex. AB-11.
[2208] 6 Tr 3780.
[2209] 6 Tr 3780-3781.
[2210] 6 Tr 3781.
[2211] 6 Tr 3784, Table CCW-6.
[2212] 6 Tr 3785; Ex. AB-12.

for a low risk regulated utility, such that he asserts that the primary weight should be given to the sustainable growth and multi-stage models of the DCF.[2213]

Mr. Walters states that he relied on two approaches for his risk premium model: calculating the annual difference between regulatory commission-authorized ROEs for utility companies and the yield on U.S. Treasury bonds since 1986, and calculating the annual difference between authorized ROEs and Moody's "A"-rated utility bond yields over the same period.[2214] He recommends an equity risk premium ("ERP") of 5.28% over Treasury bond yields and an ERP of 4.06% over "A"-rated utility bond yields.[2215] He states that adding an ERP of 5.28% over Treasury bonds to the projected 30-year Treasury yield of 4.60% produces an ROE of 9.88%, and adding an ERP of 4.06% over "A"-rated utility bond yields to the recent average "A"-rated utility bond yield of 5.86% results in a 9.92% ROE.[2216]

Mr. Walters states that he also performed a weighted least squares ("WLS") regression analysis based on the same authorized ROEs, long-term Treasury bond yields, and corresponding ERP since 1986, which results in an estimated ROE of 9.85%.[2217]

Mr. Walters states that for his CAPM analysis he used Blue Chip Financial Forecasts' projected 30-year Treasury bond yield of 4.60% as the market risk-free rate, various betas from a few sources, and market risk premium premiums of 7% and

---

[2213] 6 Tr 3785-3786.
[2214] 6 Tr 3786.
[2215] 6 Tr 3788.
[2216] 6 Tr 3789.
[2217] 6 Tr 3789-3794.

8%.[2218] He notes that his average expected market return of 11.52% exceeds long-term market expectations of several financial institutions.[2219] He states that he provided the results of twelve different applications of the CAPM, using the current average Value Line beta of 0.75, the historical Value Line beta of 0.78, the current S&P Global Market Intelligence beta of 0.42, and the proxy group's three-year beta estimate of 0.64.[2220] He states that the average results of his CAPM analysis range from 7.54% to 10.04%.[2221]

Mr. Walters states that based on his analyses of the various methodologies described above, he estimates Consumers' current market ROE to be in the reasonable range of 9.00% to 10.00%.[2222] He adds that based on his assessment of Consumers' lower overall risk profile, the results of his analytical methods, and taking into consideration Consumers' existing ROE, he recommends that this Commission authorize a ROE of 9.50%, which is the midpoint of the reasonable range of 9.00% to 10.00%.[2223]

Mr. Walters states that with prudent and reasonable adjustments to Ms. Bulkley's DCF, CAPM, and Risk Premium return estimates, her studies show that his 9.50% recommended return on equity for Consumers is reasonable.[2224]

Mr. Walters states that Ms. Bulkley's constant growth DCF results are based on growth rates of 5.19%, 6.48%, and 7.41%, respectively, which rates exceed projected

---

[2218] 6 Tr 3795-3800
[2219] 6 Tr 3800-3801, Table CCW-9.
[2220] 6 Tr 3803.
[2221] 6 Tr 3804, Table CCW-10.
[2222] 6 Tr 3805.
[2223] Id.
[2224] 6 Tr 3806.

GDP growth and thus cannot be sustained.[2225] Regarding her CAPM analysis, he states that Ms. Bulkley's DCF-derived market risk premiums are based on a market return of approximately 12.58%, and that Ms. Bulkley's sustainable market growth rate of 11.15% is far too high to be a rational outlook for sustainable long-term market growth as it is nearly three times the growth rate of the U.S. GDP long-term growth outlook of 4.09%.[2226] He states that there is no legitimate basis to use an adjusted beta within an ECAPM because it unjustifiably alters the security market line and materially inflates a CAPM return for a company with a beta less than 1.[2227] Regarding Ms. Bulkley's bond yield risk premium ("BYRP"), he notes that even though her analysis is predicated on authorized ROEs as the starting point, her average BYRP result of 10.59 % exceeds every one of the 91 ROEs awarded to electric utilities since 2024, which fact highlights the implausibility of her model's outputs.[2228] He adds that her model extrapolates a higher ERP than is consistent with recent experience, noting that she projects ERPs of 6.06% to 6.19%, even though the most recent four quarterly average ERPs observed in 2024–2025 ranged from 5.11% to 5.65% percent at very similar levels of interest rates.[2229]

e. CUB

Mr. Bandyk states that Ms. Bulkley has proposed an excessive return on equity of 10.25%, well above the current authorized ROE (9.9%), the 2024 national average for authorized ROEs (9.7%), and the cost of equity of the U.S. stock market as he

[2225] 6 Tr 3809.
[2226] 6 Tr 3811.
[2227] 6 Tr 3815.
[2228] 6 Tr 3816-3817.
[2229] 6 Tr 3817.

calculated (9.02%).[2230] He adds that this proposed ROE would increase costs to ratepayers by approximately $70 million annually relative to a market-based ROE of 9.22%.[2231] He recommends that the Commission authorize an ROE of 9.22%, which represents the midpoint between 8.63%, as calculated using objective financial methods that correct for the flaws in Consumers' analysis, and Consumers' current authorized ROE of 9.9% and would serve to more gradually reduce Consumers' ROE.[2232]

Mr. Bandyk states that estimating the cost of equity for a regulated utility must be done carefully so as to arrive at a return that ensures rates that are "just and reasonable," a principle elaborated on in the landmark U.S. Supreme Court cases that set the legal standards governing public utility regulation, *Bluefield* and *Hope*.[2233] He adds that the Court was also clear that the determination of what return is "sufficient" must also involve a consideration of the interests of the company's customers, as a return for a utility that is set below the amount "commensurate with returns on investments in other enterprises having corresponding risks" causes the utility to lose wealth relative to what it should earn with a more appropriate return, a return that is set above this amount will cause the utility's customers to be overcharged and lose wealth, with that wealth instead being transferred from customers to the utility holding company's shareholders.[2234]

Mr. Bandyk states that there is strong evidence from multiple observers and peer-reviewed academic research that public regulatory commissions have tended to

---

[2230] 6 Tr 3944.
[2231] Id.
[2232] 6 Tr 3945.
[2233] 6 Tr 3946.
[2234] 6 Tr 3947.

set electric utility ROEs above the "market-based ROE."[2235] He adds that the trend in commissions approving ROEs that exceed a market-based ROE has resulted in a transfer of wealth from ratepayers to shareholders and resulted in a skewed average authorized ROE.[2236] He states that statistical evidence shows that the utility ROEs are increasingly being set above the actual cost of equity, as shown by how the authorized ROE premium over the 10-year treasury yield has grown from approximately 3 percent in the mid-1980s to nearly 8 percent in recent years.[2237]

Mr. Bandyk states that a higher return implies higher risk, so approving ROEs that are higher than market returns would imply that regulated utilities are riskier investments than the market as a whole.[2238] He asserts that this is contradictory as regulated utility returns tend to be less risky than the market as a whole, indicating that regulatory decisions are not in line with the economic reality that lower risk means lower return.[2239]

Mr. Bandyk states that utilities are less risky than the market as a whole as shown by Beta, which is a measurement of the sensitivity of a stock's returns relative to those of the market as a whole.[2240] He adds that utility holding company betas tend to be less than one, meaning that those stocks are less sensitive to changes in overall market returns.[2241]

[2235] 6 Tr 3948
[2236] Id.
[2237] 6 Tr 3949. Citation omitted.
[2238] 6 Tr 3950.
[2239] Id.
[2240] 6 Tr 3951.
[2241] Id.

Mr. Bandyk states that, despite regulated utilities being less risky than the market as a whole, regulated utilities have been awarded ROEs above market returns as public regulatory commissions have tended to accept estimates for ROE that are above fair, market-based ROE estimates.[2242] In this regard, Mr. Bandyk explains the influence of utilities in the regulatory process have contributed to commissions approving ROE's that exceed the market-based ROE.

> Determining the market-based ROE is inherently an exercise in estimation, which invariably includes some degree of subjectivity. Subjective factors can influence any human decision-making process, including the decisions of public utility regulatory commissions, leading to unintended results. These factors include the influence of utilities in the regulatory process. Utilities often have more resources to advocate for higher ROEs and amplify their position more effectively than opposing groups, regardless of whether their arguments are stronger. This imbalance can skew regulatory outcomes and undermine the public interest.[2243]

Mr. Bandyk states that both the 9.9% current ROE and the 10.25% proposed ROE are significantly higher than the 9.7% average ROE authorized by state regulatory commissions in 2024.[2244] He asserts that the fact that there is evidence that nationally utility ROEs are set too high and that Consumers' proposed ROE is higher than average strongly suggests that Consumers' proposed ROE is excessive.[2245]

Mr. Bandyk disagrees with Ms. Bulkley claims that "an authorized ROE significantly below authorized ROEs for other utilities can inhibit the utility's ability to attract capital for investment," asserting that she is conflating the cost of equity with the

---

[2242]
[2243] 6 Tr 3943.
[2244] 6 Tr 3952. Citation omitted.
[2245] Id.

authorized ROE of other utilities.[2246] He asserts that ROEs authorized for peer utilities are not the same as the actual cost of equity, and as regulatory commissions routinely set authorized ROEs well above the actual cost of equity for utilities, we cannot look to other jurisdictions to determine the opportunity cost for investors.[2247] He states that an ROE can be set below the national average for authorized ROEs and still be above the cost of equity – meaning that ROE still provides a return to investors that is more than adequate to attract the required capital.[2248]

Mr. Bandyk states that if the Commission were to approve Consumers' request for a rate increase without changes, Consumers would collect about $975.36 million from customers for a return on its rate base, based on an overall rate of return of 6.35% and a total jurisdictional rate base of $15.36 billion.[2249] He asserts that if the ROE were instead the market-based ROE of 9.22% that he recommends, along with his proposed 50/50 debt-equity ratio, the overall rate of return would fall to 5.89% and the amount collected would fall from $975.36 million to $904.70 million, resulting in savings to customers of about $70.65 million per year.[2250]

Mr. Bandyk states that his ROE estimate is based on the Capital Asset Pricing Model (CAPM) and the Discounted Cash Flow (DCF) methods, and that he used the same proxy group as Ms. Bulkley.[2251] He adds that the results of his DCF and CAPM analyses are a DCF average of 8.96% and a CAPM average of 8.11%, the average of

---

[2246] Id. Citation omitted.
[2247] 6 Tr 3952-3953.
[2248] 6 Tr 3953.
[2249] 6 Tr 3953, citing Ex. A-14, Sch. D-1, Ex. A-12, Sch. B-1..
[2250] Id., citing Ex. CUB-2.
[2251] 6 Tr 3954.

which is 8.53%.[2252] He recommends an ROE for Consumers of 9.22%, which represents the midpoint between the 8.53% average result reached by my application of the DCF and CAPM models and the 9.9% ROE currently authorized for Consumers, reasoning that any significant changes in Consumers' ROE should be implemented gradually so as 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.[2253]

Mr. Bandyk states that his CAPM analysis follows the same basic formula as Ms. Bulkley's, but that the values we use for several important inputs to the formula – the equity risk premium (ERP), beta and the risk-free rate – differ.[2254]

For his ERP – which represents the excess return an investor would receive over the risk-free rate by investing in the broader equity market – Mr. Bandyk used two sources.[2255] He notes that Ms. Bulkley's calculation of the ERP assumes that cash flows will grow in the long term at a constant rate based on analyst expectations of the next five years, rather than settling at a more sustainable long-term rate based on the risk-free rate, which assumption that earnings can grow in perpetuity at such a high rate is unrealistic.[2256]

Mr. Bandyk states that he used two risk-free rates: the risk-free rate of 4.23%, representing the current yield on long-term Treasury bonds and the spot 20-year Treasury yield of 4.76%.[2257] He adds that used as beta two different averages: the average of the Value Line beta estimates for the companies in his proxy group, and the

---

[2252] 6 Tr 3954-3955.
[2253] 6 Tr 3955-3956.
[2254] 6 Tr 3956; Ex. CUB-5
[2255] 6 Tr 3957-3960. Citations omitted.
[2256] 6 Tr 3961.
[2257] 6 Tr 3962; Ex. CUB-3.

average of the Bloomberg beta estimates for the companies in his proxy group.[2258] He adds that for each of the two betas, he removed the Blume adjustment to convert "raw" betas to "adjusted betas", which is not appropriate to apply to betas of rate regulated utilities.

> The ability to recover costs inoculates rate-regulated utilities from systematic risk. Rate regulation protects investor-owned utilities like Consumers Energy from the risks of rising expenses, commodity price risk, and competitive risks, and they enjoy natural monopolies that mitigate market risks associated with the customer base. For example, commodity prices tend to be passed through directly to customers, and utilities can request a rate increase if sales decline.[2259]

Thus, Mr. Bandyk calculated the cost of equity using four different CAPM formulas to account for two different ERPs (Damodaran and Kroll) and two different average betas (Value Line and Bloomberg).[2260]

Mr. Bandyk states that the expected return of the U.S. stock market can be calculated using the CAPM inputs but using a beta of 1, and that he calculated a 9.02% return for the U.S. stock market.[2261]

Mr. Bandyk states that to his knowledge, the Commission has never recognized the ECAPM as a valid methodology for estimating ROE, and that the MPSC Staff has also historically declined to use the ECAPM model as part of its ROE analyses.[2262]

Mr. Bandyk states that for his DCF analysis, he added Consumers' growth rate to the dividend yields of each company in my proxy group to arrive at an estimated cost of

---

[2258] 6 Tr 3963.
[2259] 6 Tr 3964.
[2260] 6 Tr 3965; Ex. CUB-5.
[2261] Id.; Ex. CUB-10.
[2262] 6 Tr 3966. Citations omitted.

equity.[2263] He adds that his DCF result is lower than Ms. Bulkley's primarily due to correcting for Ms. Bulkley's use of an unrealistic growth rate.[2264] He states that the EPS projections used by Ms. Bulkley are all in the short term -- five-year consensus analyst earnings per share growth estimates -- but a short-term growth rate cannot be the only growth rate used in the DCF model.[2265] He asserts that the average of her EPS growth rates is 6.48%, which is over 70% higher than the Congressional Budget Office's forecast of 3.80% for the average annual GDP growth of the U.S. economy from 2028 to 2035.[2266] He states that a DCF growth rate input higher than the growth rate of the economy as a whole implies that, in the long run, Consumers will grow larger than the entire U.S. economy, and that such an outcome is impossible.[2267]

Mr. Bandyk states that he used two versions of the DCF model: a two-stage DCF model that includes a weighted average of a short-term growth rate based on investor expectations of utility earnings growth and a long-term growth rate that matches investor expectations of the growth of the domestic economy as a whole, and another version of the DCF model that is identical to the first except the short-term growth rate is the average of the Value Line forecasts for dividend per share growth of the proxy group companies, rather than an average of forecasts for earnings growth.[2268]

Mr. Bandyk asserts that the Commission should not consider Ms. Bulkley's Bond Yield Risk Premium (BYRP) analysis for estimating ROE, as it involves the calculation of ROE in reliance on ROEs set by other regulatory commissions, which is both circular

---

[2263] Id.
[2264] Id.
[2265] Id.
[2266] 6 Tr 3967, citing Ex. A-14, Sch. D-5 and Ex. CUB-6.
[2267] Id.
[2268] 6 Tr 3967-3969; Ex. CUB-6. Citations omitted.

and would likely result in the continuation of excessively high ROEs.[2269] Mr. Bandyk states that, in that regard, in Opinion No. 569 in a 2019 order, FERC found that "while all models, including the DCF, feature some circularity, such circularity is particularly direct and acute with the Risk Premium model because it directly relies on past Commission ROE decisions."[2270] He notes that in that decision, FERC also rejected the use of the Risk Premium model because it is "largely redundant with the CAPM."[2271]

Mr. Bandyk disagrees with Ms. Bulkley's claims that Consumers' level of capital expenditures gives Consumers higher risk relative to the proxy group, and that if Consumers' proposed infrastructure recovery mechanism is not approved, this additional risk "supports an ROE toward the higher end of the reasonable range of ROEs,", asserting that these risks have already been accounted for in Consumers' credit rating, which rating compares favorably to the ratings of the proxy group companies, thus indicating that Consumers is not at higher risk due to its planned capital expenditures.[2272] He adds that Consumers currently has an A- long-term credit rating from S&P, which rating is higher than the ratings for all but 5 of the 19 proxy group companies.[2273]

f. Walmart

Mr. Lyon does not estimate the cost of equity for Consumers but rather evaluates average authorized ROEs for electric utilities nationally from 2023 through thus far in 2025.

[2269] 6 Tr 3970.
[2270] 6 Tr 3971, citing FERC Opinion 569, 169 FERC 61129 (2019), par. 343.
[2271] Id.
[2272] 6 Tr 3971-3972.
[2273] 6 Tr 3972. Citation omitted.

Mr. Lyon states that Walmart believes that Consumers' proposed ROE of 10.25% is excessive, especially in light of: (1) the customer impact of the resulting revenue requirement increase; (2) the reduced risk associated with Michigan's regulatory framework and Commission precedent, including the (i) use of a projected split-test year (which reduces the risk due to regulatory lag based on the inclusion of the most current information in its rates when they will be in effect), (ii) inclusion of CWIP in rate base, and (iii) alternative recovery mechanisms such as the currently approved Distribution IRM Surcharge; and (3) the reported average ROE authorized for regulated utilities in Michigan and the United States for the last two or more years.[2274]

Mr. Lyon states that, using Consumers' proposed rate base, cost of debt, and capital structure, the impact of the change to Consumers' proposed ROE of 10.25% is approximately $30.8 million, or 7.06% of the proposed revenue deficiency.[2275] He notes that the Commission has recognized that Michigan's regulatory framework significantly reduces utility risk, thereby necessitating that the Commission take a conservative approach to setting an ROE, stating:

> Act 286 (1) allows Michigan utilities to use projected test year revenues, expenses, and sales volumes in support of any requested rate increases, (2) provides for the possibility of self-implementation of all or part of a requested rate change within 180 days following submission of an application, (3) requires that the Commission issue a final order concerning the application within 365 days from its filing, lest the request be automatically implemented, and (4) restricts the amount of retail choice to 10% of a utility's total sales. These changes in Michigan's regulatory framework, which tend to lean heavily in favor of the utilities and their investors by significantly reducing the risk borne by such companies in the

[2274] 3 Tr 2606.
[2275] 3 Tr 2607; Ex. WAL-2.

> past, necessitate taking a conservative approach with regard to the specific ROE authorized in rate cases like this.[2276]

He adds that when setting ROE the Commission should continue to recognize the effect of Michigan's regulatory framework on utility risk, including the risk reducing impact of including CWIP in rate base.[2277]

Mr. Lyons states that since 2023, this Commission has issued orders with stated ROEs in nine cases, with the most recent ROE approved earlier this year, and that the average of these approved ROEs is 9.89%.[2278] He adds that the Commission issued orders with stated ROEs in the following cases: Case No. U-21224, Consumers general rate case that completed in 2023, in which the Commission approved an ROE of 9.90%; Case No. U-21389, Consumers' general rate case that completed in 2024, in which the Commission approved an ROE of 9.90%; and Case No. U-21585, Consumers' last general rate case that completed in 2025, in which the Commission approved an ROE of 9.90%.[2279] He asserts that Consumers' proposed 10.25% ROE is counter to recent Commission actions regarding ROE.[2280]

Mr. Lyons states that Consumers' proposed ROE is significantly higher than the ROEs approved by other utility regulatory commissions since 2023.[2281] He adds that according to data from S&P Global Market Intelligence ("S&P Global"), the average of the 104 reported electric utility rate case ROEs authorized by commissions to investor-owned utilities since 2023 is 9.68%, with the range of reported authorized ROEs for the

---

[2276] 3 Tr 2607-2608, quoting Case No. U-16472, Order, October 20, 2011, p. 39, citing PFD dated August 12, 2011, p. 49.
[2277] 3 Tr 2608.
[2278] 3 Tr 2608-2609; Ex. WAL-3.
[2279] 3 Tr 2609-2610; Ex. WAL-3.
[2280] 3 Tr 2610.
[2281] 3 Tr 2610.

period being 8.63% to 11.45%, and the median authorized ROE being 9.70%.[2282] He states that the average and median values are significantly below Consumers' proposed ROE of 10.25%, and as such, Consumers' proposed 10.25% ROE is counter to broader electric industry trends.[2283]

Mr. Lyons states that in the group reported by S&P Global, the average ROE authorized for vertically integrated utilities since 2023 is 9.77%, with the average ROE authorized for vertically integrated utilities is 9.71% in 2023, 9.85% in 2024, and 9.74% so far in 2025.[2284] He adds that Consumers' proposed ROE would be the sixth highest approved ROE for a vertically integrated utility from 2022 to present if approved by the Commission.[2285]

Mr. Lyons states that if the Commission awarded Consumers an authorized ROE of 9.77% instead of the requested 10.25%, it would result in a reduction to the requested revenue requirement increase of about $42.4 million.[2286]

Mr. Lyons states that according to Vanguard, the 10-year annualized nominal return and volatility forecast for U.S. equities ranges from 3.3 to 5.3%, based on the June 30, 2025, running of the Vanguard Capital Markets Model®.[2287]

Mr. Lyons recommends that the Commission closely examine Consumer's proposed revenue requirement increase and the associated ROE, especially when viewed in light of: (1) the impact of the resulting revenue requirement increase on customers; (2) the reduced risk associated with Michigan's regulatory framework and

---

[2282] Id.; Ex. WAL-3.
[2283] 3 Tr 2611.
[2284] 3 Tr 2611-2612; Ex. WAL-3.
[2285] 3 Tr 2612-2613, Figure 1.
[2286] 3 Tr 2614.
[2287] 3 Tr 2615, Figure 2.

Commission precedent, including the use of a projected test year, inclusion of CWIP in rate base, and alternative recovery mechanisms such as the currently approved Distribution IRM Surcharge; and (3) recent ROEs approved in Michigan and other jurisdictions nationally.[2288]

g. Rebuttal

Ms. Bulkley states that, while she updated her cost of equity analyses based on market data through September 30, 2025 and with a revised proxy group, her results continue to support the ROE range of 10.25% to 11.25% that she recommended in her direct testimony and Consumers' requested ROE of 10.25%.[2289] She adds that while the analytical results of the cost of equity estimation models provide a starting point, she continues to base her 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.[2290]

Ms. Bulkley states that the primary factors that should be considered in evaluating the results of the cost of equity analyses and establishing the authorized ROE 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

[2288] 3 Tr 2617.
[2289] 4 Tr 2794.
[2290] Id.

and expected capital market conditions; and (4) achieving a reasonable balance between the interests of investors and customers.[2291]

Ms. Bulkley lists the updated results of her analyses in Exhibit A-206.[2292] She states that the results of each of the DCF analyses have increased since the filing of her direct testimony, while the results of her CAPM and ECAPM analyses are generally consistent with those filed in my direct testimony and the results of the Bond Yield Risk Premium have generally increased modestly since the filing of her direct testimony.[2293]

Ms. Bulkley states that based on an estimated market capitalization-weighted dividend yield of 1.36% and a weighted long-term growth rate of 11.15%, the estimated required market return for the S&P 500 Index at the time of her direct testimony was 12.58% and based on more recent data through September 2025, the estimated expected market return is for the broader stock market 13.34%.[2294]

Regarding the 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% -- she states that she has two concerns. She states that studies have shown that investment firms have not accurately forecasted actual returns and that investment firms often also provide a range of return expectations, which ranges highlight the significant degree of uncertainty associated with their forecast estimates.[2295]

[2291] 4 Tr 2795.
[2292] 4 Tr 2799.
[2293] 4 Tr 2799-2800.
[2294] 4 Tr 2800-2801; Ex. A-14, Sch. D-5, p. 16; Ex. A-206, p. 15-20.
[2295] 4 Tr 2801-2802.

Ms. Bulkley states that 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 other regulated utilities with comparable risk.[2296] She adds that it is important to screen this data to consider only the returns that have been authorized for risk-comparable companies and 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.[2297]

Ms. Bulkley states that she analyzed the recently authorized returns for vertically-integrated electric utilities using various screening criteria, concluding that over the past five years, authorized ROEs for vertically-integrated electric utilities have increased.[2298] She adds that Messrs. Megginson, Coppola, and Walters 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.[2299]

Ms. Bulkley states that she disagrees with Mr. Bandyk's claim that regulators have incorrectly authorized ROEs substantially higher than the cost of equity for decades, asserting that he has provided no evidence that supports his position that regulatory commissions, including this Commission, have consistently erred for decades in establishing utilities' ROEs.[2300] She states that none of the sources he cites credibly

---

[2296] 4 Tr 2802-2803.
[2297] 4 Tr 2803.
[2298] 4 Tr 2803-2804, Figure 3.
[2299] 4 Tr 2804
[2300] 4 Tr 2807.

support Mr. Bandyk's claim that "public regulatory commissions have tended to accept estimates for ROE that are above fair, market-based ROE estimates."[2301]

Ms. Bulkley states that she disagrees with the proxy groups chosen by Staff, the Attorney General, ABATE and MEC.[2302] Similarly, she states that she disagrees with the inputs used and results obtained by these parties for their DCF,[2303] CAPM,[2304] and Bond Yield Risk Premium analyses.[2305]

Ms. Bulkley states that she disagrees with Messrs. Megginson, Coppola, Walters, and Bandyk regarding the business and financial risks of Consumers.[2306] Regarding Mr. Walters's and Mr. Bandyk's assessment of the relative risk of Consumers based on relative credit rating comparisons, Ms. Bulkley states that she disagrees 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 [Consumers'] equity."[2307] She adds that "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."[2308] She argues that, because the proxy companies do not have exactly the same risk profile as the subject company, it is reasonable to compare the relative risks of the proxy group companies and the subject company "to determine the appropriate placement of the ROE within the range of results established using the

---

[2301] 4 Tr 2813-2816.
[2302] 4 Tr 2816-2825.
[2303] 4 Tr 2825-2844.
[2304] 4 Tr 2844-2883.
[2305] 4 Tr 2883-2907.
[2306] 4 Tr 2912-2916.
[2307] 4 Tr 2914
[2308] Id.

proxy group companies."[2309] In this regard, she concludes that Consumers has "slightly greater regulatory and business risk than the proxy group."[2310]

h. Recommended ROE

In reviewing the different analyses and evidence presented by the witnesses, this PFD finds that Consumers' recommended return of 10.25% is excessive, is contrary to the Supreme Court standards, is unsupported by record evidence, and thus should be rejected.

Consumers, Staff, the Attorney General and ABATE each chose a proxy group of comparable publicly traded utilities, to which they applied various models to approximate comparable ROE returns for Consumers.

Consumers, Staff, the Attorney General, ABATE and CUB each applied the CAPM and DCF models. Consumers, the Attorney General and ABATE each also applied a Risk Premium model, while Consumers separately applied an ECAPM. As discussed, the parties take issue with the use of the Risk Premium model and the ECAPM. The parties also take issue with various inputs used with, and the results of, the models.

The CAPM methodology estimates the cost of equity by taking the "risk-free rate" and adding to it the "market-risk premium" multiplied by "beta." Regarding Consumers' CAPM model estimates, the Attorney General argues that Consumers developed its market risk premium (MRP) input based on future expected stock price growth rates and dividends for a select group of companies from the S&P 500 stock index over the

[2309] 4 Tr 2915.
[2310] Id.

next three to five years, instead of using a proven historical MRP.[2311] Mr. Coppola also argues that Consumers' approach in developing a projected MRP is problematic as approximately 25% of the companies in the list of S&P 500 Index with dividend yields and long-term growth estimates are omitted from Consumers' calculation of its 13.34% stock market return.[2312]

This PFD notes that Consumers' use of projected earnings growth to estimate the expected return for the CAPM is appropriate. *See, e.g.*, FERC Opinion 569:

> The expected return can be estimated either using a backward-looking approach, a forward-looking approach, or a survey of academics and investment professionals. A CAPM analysis is backward-looking if the expected return is determined based on historical, realized returns. A CAPM analysis is forward-looking if the expected return is based on a DCF analysis of a large segment of the market.[2313]

Regarding Consumers' calculation apparently excluding 25% of the S&P companies, Ms. Bulkley counters that S&P 500 Index companies are only excluded from her constant growth DCF analysis if their projected earnings per share (EPS) growth rate was either negative or greater than 20%.[2314] This PFD notes that Ms. Bulkley's exclusion parameters have been recognized as being appropriate for use in a CAPM analysis.[2315]

However, Ms. Bulkley's exhibit showing the calculation of her projected market return appears to indicate that some companies that are not paying dividends are

---

[2311] 3 Tr 2546.
[2312] 3 Tr 2547, referencing Ex. A-14, Sch. D-5, p. 16-21. It is noted that Ms. Bulkley's estimated market return in her direct testimony was 12.58%, while her estimated market return in her rebuttal testimony was adjusted based on more recent data to 13.34%. 4 Tr 2800-2801.l
[2313] FERC Opinion 569, 169 FERC 61129, November 21, 2019, par. 229.
[2314] 4 Tr 2871, citing Ex. A-14, Sch. D-5, p. 16-21.
[2315] FERC Opinion 569, par. 268.

included in Consumers' calculation.[2316] Such inclusion is improper. See, FERC Opinion 569:

> [U]sing a forward-looking approach to estimate the CAPM expected market return based on applying the DCF model to the dividend paying members of the S&P 500 is a well-recognized method of estimating the expected market return for purposes of the CAPM model. The DCF analysis must be limited to the dividend-paying members of the S&P 500, rather than using all companies in the S&P 500, because a DCF analysis can only be performed on companies that pay dividends.[2317]

Indeed, Ms. Bulkley acknowledges that companies that do not pay cash dividends cannot be analyzed using the Constant Growth DCF model.[2318]

The Attorney General asserts that Consumers is using an extremely short 3-to-5-year period to measure stock market returns in calculating the market risk premium.[2319] Similarly, ABATE argues that Consumers' CAPM results are inflated as Ms. Bulkley's DCF-derived market return (12.58%) uses a market growth rate that is too high for sustainable long-term growth, noting that her growth rate (11.15%) is nearly three times the growth rate of the U.S. GDP long-term growth rate.[2320] CUB argues that Ms. Bulkley's use of a three-to-five year EPS growth rate improperly assumes that cash flows will grow in the long term at a constant rate based on analyst expectations of the next five years.[2321]

However, the use of a short-term growth rate in the DCF analysis within CAPM has been recognized as appropriate, as the use of the DCF analysis in CAPM differs from using the DCF analysis directly to estimate an ROE:

[2316] Ex. A-206, p. 15-21.
[2317] FERC Opinion 569, par. 260. Citation omitted.
[2318] 4 Tr 2735.
[2319] 3 Tr 2547.
[2320] 6 Tr 3811.
[2321] 6 Tr 3961.

> The Commission's rationale for incorporating a long-term growth rate estimate in DCF analyses for public utilities is that it is often unrealistic and unsustainable for high short-term growth rates to continue in perpetuity for a particular utility or group of utilities. The purpose of the DCF analysis in the CAPM model differs from the purpose of using the DCF analysis to directly estimate a utility's cost of equity. The purpose of the DCF analysis in the CAPM model is to determine the "required return on the overall market" that will be used to determine the market risk premium—which is based on the difference between the "required return on the overall market" and the risk-free rate.
>
> While it may be unreasonable to expect an individual company to sustain high short-term growth rates in perpetuity, the same cannot be said for a broad representative market index that is regularly updated to include new companies. Put differently, a portfolio of companies behaves differently than an individual company. Accordingly, the rationale for incorporating a long-term growth rate estimate in conducting a two-step DCF analysis of a specific utility or group of utilities for purposes of directly estimating cost of equity does not apply to the DCF analysis of a broad representative market index with a wide variety of companies that is regularly updated to include new companies for purposes of determining the required return to the overall market.[2322]

ABATE asserts that Consumers' CAPM analysis relies on current Value Line betas which are overstated, while CUB argues that the Blume adjustment – which converts "raw" betas to "adjusted" betas – needs to be removed from the betas used by Consumers.[2323] Consumers' counters that the raw betas used by Mr. Bandyk and the adjusted betas used by Mr. Walters likely understate the true beta of utility stocks.[2324] This PFD finds that the betas used by Consumers, ABATE and CUB (and Staff and the Attorney General) are reasonable, noting that there is support for using both raw and adjusted betas[2325] and that the parties use multiple betas in their CAPM analyses.[2326]

[2322] FERC Opinion 569, par. 263, 266. Citations omitted.
[2323] 6 Tr 3812; 6 Tr 3963-3964.
[2324] 4 Tr 2861.
[2325] FERC Opinion 569, par. 297; 6 Tr 3964, n. 28; 6 Tr 3965, n. 29.
[2326] Ex. A-206, p. 5-14; Ex. AB-18, Ex. AB-19; Ex. CUB-4, Ex. CUB-5.

Staff, the Attorney General, ABATE and CUB all assert that Consumers' CAPM results are excessive. Staff argues that Consumers' market risk premiums are substantially higher than the historical market risk premium.[2327] Similarly, ABATE argues that Consumers' estimated ROE is overstated as its CAPM results are inflated.[2328] CUB asserts that Consumers' calculation of the market risk premium is flawed, resulting in an excessive proposed ROE.[2329]

Ms. Bulkley counters that the market return, and thus market risk premium, in her CAPM analyses are reasonable and consistent with the findings of the Federal Reserve and other utility regulatory commissions.[2330] In this regard, Ms. Bulkley points to the Federal Reserve Bank of New York publishing an analysis in 2015 that reviewed 20 methodologies over the period 1960 through 2013 for estimating the market risk premium.[2331] She asserts that the result of this study demonstrates that her market risk premium estimates, which are in the range of 8.55% to 8.94%, are reasonable, noting that one of the "key conclusions" from the study is that the 20 methodologies reviewed reflected a range for the market risk premium of between -1.00% to 14.50%.[2332]

This PFD finds that Ms. Bulkley's reliance on this Report is misplaced. The Report includes the following statements material to Ms. Bulkley's assertions: a) the authors estimated the equity risk premium by combining information from twenty

---

[2327] 6 Tr 4523.
[2328] 6 Tr 3808.
[2329] 6 Tr 3944.
[2330] 4 Tr 2870.
[2331] 4 Tr 2867, citing Fernando Duarte and Carla Rosa, "The Equity Risk Premium: A Review of Models," Federal Reserve Bank of New York (2015). As with most of the articles and materials Ms. Bulkley references and quotes in her testimony, this Staff Report No. 714 ("Report") was not admitted as an exhibit in this case. However, this Report was a Consumers' exhibit admitted in Case No. U-21389 as Exhibit A-172.
[2332] Id.

models, and concluded that the one-year-ahead equity risk premium in June 2012 was 12.2%, b) the equity risk premium was high because Treasury yields were "unusually low", while the expected stock returns were close to their long-run average, and c) there remains "considerable uncertainty around these estimates" and that the issue of whether stock returns are predictable "is still an active area of research."[2333] Most significantly, regarding the -1.00% to 14.50% range Ms. Bulkley asserts supports her calculated market risk range of 8.55% to 8.94%, the Report states that the average equity risk premium of all of the models as well as the historical average equity risk premium for the five years prior to the study period were both 5.7%.[2334] Thus, the Report's compilation shows that Consumers' market risk premium is excessive, which inflates its CAPM results.

This PFD finds that Consumers' CAPM analysis results are unreliable as Ms. Bulkley's calculation of its projected market return apparently included some companies that are not paying dividends, and excessive as shown by her market risk premiums being well above the averages calculated by the Federal Reserve report she cites, by the historical market risk premium cited by Staff, and the market risk premiums calculated by other parties. Accordingly, this PFD shall not consider the results of Consumers' CAPM analysis.

Ms. Bulkley also estimated an ROE using an Empirical Capital Asset Pricing Model (ECAPM), which she argues addresses the tendency of the traditional CAPM to underestimate the cost of equity for companies with low betas like regulated utilities.[2335]

[2333] Report, p. 1, 2; Case No. U-21389, Ex. A-172, p. 3, 4.
[2334] Report, p. 12-13: Case No. U-21389, Ex. A-172, p. 31.
[2335] 4 Tr 2746-2747.

Staff, the Attorney General, ABATE and CUB assert that the ECAPM model should not be considered.

Staff argues that the inputs used for CAPM make the ECAPM adjustment unnecessary.[2336] The Attorney General asserts that there is academic disagreement with the use of ECAPM and that ECAPM produces an inflated cost of equity.[2337] ABATE argues that there is no legitimate basis to use an adjusted beta within an ECAPM because it inflates a CAPM return for companies with a beta less than 1.[2338] CUB asserts that the Commission has never recognized the ECAPM as a valid methodology for estimating ROE and that the Staff has historically declined to use ECAPM.[2339]

This ALJ notes that Consumers has not identified an order whereby the Commission has previously recognized the use of the ECAPM model. In addition, it is noted that FERC does not recognize the use of ECAPM, which it considers to be an "obscure" and "more controversial" variant of CAPM.[2340] More significantly, this PFD notes that the Commission "has consistently taken a traditional approach" to establishing ROE, focusing on the "most commonly-used, fundamental approaches" to determining a just and reasonable ROE.[2341] Accordingly, this PFD finds that Consumers' ECAPM estimates should not be considered.

Regarding the DCF method, Consumers, Staff, the Attorney General, ABATE and CUB all calculated DCF estimates, albeit with different inputs and with the most disputed input being the applicable growth rate.

[2336] 6 Tr 4553.
[2337] 6 Tr 2548-2549.
[2338] 6 Tr 3815.
[2339] 6 Tr 3966.
[2340] See, Initial Decision, 153 FERC 63027 (2015), par. 332.
[2341] Case No. U-20940, Order, December 9, 2021, p. 91.

Staff and the Attorney General argue that some of the growth rates for the companies in Consumers' proxy group are unreasonable and inflate the results. Staff points to the growth rate for Dominion Resources which produces a DCF ROE of over 15%.[2342] The Attorney General argues that, in addition to Dominion, the growth rates for Avista and NextEra are "higher".[2343] This PFD agrees that the ROE estimate for Dominion is an outlier which skews Consumers' DCF results. However, this PFD finds that the growth rates for Avista and NextEra are not so high as to be excluded as outliers. Thus, this PFD shall consider an adjusted DCF model result by Consumers which excludes Dominion.[2344]

Consumers counters that Staff's DCF results include its own anomalous result for Pinnacle West, which Consumers argues is "far below the rest of the DCF results."[2345] This PFD agrees and thus shall consider an adjusted Staff DCF estimate excluding Pinnacle.[2346]

ABATE and CUB assert that Consumers' short-term EPS estimates are significantly higher than forecasts for projected GDP growth (4.09%, 3.80%), which cannot be sustained, and because of which Consumers should have considered the results of a two-step or multi-stage DCF.[2347] Ms. Bulkley counters that ABATE's and CUB's use of multi-stage DCF analyses are improper as the utility is considered a

---

[2342] 6 Tr 4551. The Attorney General argues that, in addition to Dominion, the growth rates for Avista and NextEra are "higher".
[2343] 3 Tr 2542.
[2344] The average of the mean growth rates without Dominion is 10.21%. Ex. A-206, p. 2-4.
[2345] 4 Tr 2827.
[2346] The average of the one-step DCF estimate without Pinnacle is 10.07%. Ex. S-4, Sch. D-5, p. 5.
[2347] 6 Tr 3785, 3809; 6 Tr 3966-3968.

mature industry due to its regulated status and relatively stable demand.[2348] Ms. Bulkley also argues that there is no basis to Messrs. Walters and Bandyk's assertions that projected EPS growth rates are unsustainable.[2349]

This PFD agrees that Consumers short-term 3-year growth rate (as well as Staff's growth rates) is misleading as a short-term growth rate cannot exceed the anticipated growth rate for the economy as a whole. This PFD notes that FERC requires a multi-stage DCF analysis in order to address the limitations of only using a short-term growth rate.

> The DCF model is based on the premise that an investment in common stock is worth the present value of the infinite stream of future dividends discounted at a market rate commensurate with the investment's risk. Corporations have indefinite lives and therefore will pay dividends for an indefinite period. For that reason, the Commission stated as long ago as 1983, when it first adopted the constant growth DCF model for gas pipeline cases, that 'projections by investment advisory services of growth for relatively short periods of years into the future' cannot be relied on 'without further consideration.' Thus, as the Commission held in *Ozark*, the constant growth DCF model requires consideration of long-term growth projections.
>
> The problem is that from the standpoint of the DCF model that extends into perpetuity, analysts' horizons are too short, typically five years. It is often unrealistic for such growth to continue into perpetuity. A transition must occur between the first stage of growth forecast by analysts for the first five years and the company's long-term sustainable growth rate ... It is useful to remember that eventually all company growth rates, especially utility service growth rates, converge to a level consistent with the growth rate of the aggregate economy.[2350]

[2348] 4 Tr 2838.
[2349] 4 Tr 2841-2843.
[2350] FERC Opinion 569, par. 151, 152.

Accordingly, this PFD agrees with Mr. Walters that Ms. Bulkley's (and Mr. Megginson's) DCF model results should be considered "high-end return estimates" and thus weighted accordingly.

Ms. Bulkley criticizes Mr. Walters' weighting of his three DCF model results as being inconsistent with the weighting he gave to his results in prior cases.[2351] Similarly, Ms. Bulkley criticizes Mr. Coppola for using different growth rates than he used in Consumers' most recent gas rate case.[2352] This PFD does not find these or other similar criticisms to be meaningful. The relevant issue for any party in any case is whether their approach to estimating an ROE is reasonable and supported, not whether their approach is the same as that used in other cases. Indeed, in this ALJ's experience, parties, including Consumers, often change the bases for their recommended ROEs.[2353]

Separately, Ms. Bulkley argues that neither the results from Mr. Walters' multi-stage DCF (8.62%) nor Mr. Bandyk's two-step DCF results (8.96%) are reasonable, asserting that these results are "well below the low end" of the range of comparable authorized returns "in at least the last 45 years."[2354] This PFD disagrees, finding those results reasonable and supported by record evidence. Moreover, this PFD notes that Ms. Bulkley does not reference any support for her statement in the record in this case or otherwise. In addition, her statement is expressly contradicted by evidence submitted in two recent Commission cases which show authorized electric ROEs of 8.57% and

---

[2351] 4 Tr 2831-2832.
[2352] 4 Tr 2828-2829.
[2353] *See, e.g.*, Consumers' criteria for choosing its proxy group in Consumers' last electric rate case (Case No. U-21585, PFD, January 27, 2025, p. 323) and Ms. Bulkley's criteria for choosing her proxy group in this case. (4 Tr 2735).
[2354] 4 Tr 2837.

8.70% from 2021, 8.57% and 7.85% from 2022, and 8.63%, 8.72% and 8.91% from 2023.[2355]

This PFD concludes that the parties' DCF results as adjusted and weighted aforesaid, shall be considered.

Regarding the risk premium analyses, Ms. Bulkley estimated the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds, using authorized returns for vertically integrated electric utilities as the historical measure of the cost of equity.[2356] Similarly, Mr. Walters estimated the equity risk premium by calculating the difference between regulatory commission authorized ROEs on the one hand and the yields on U.S Treasury bonds and utility bonds on the other.[2357] Staff performed its risk premium analysis using the historical electric utility realized stock returns, historical utility bond yields and the yields on public utility bonds.[2358] Similarly, the Attorney General used projected U.S. Treasury bond rates, 30-year "A" rated utility bond rates and the historical rate of electric utility stock returns.[2359]

Mr. Megginson asserts that Consumers' bond yield + risk premium analysis should be given no weight, arguing in part that the use of historical authorized ROEs as a market return source in a cost of equity model is circular.[2360] Mr. Coppola asserts that Consumers' risk premium analysis is flawed, arguing that it is the actual return on utility equities that is the key and necessary measurement in any risk premium analysis, and

---

[2355] See, Case No. U-21389, Exhibit AG-1.22 and Case No. U-21585, Ex. AG-1.21.
[2356] 4 Tr 2748.
[2357] 6 Tr 3766.
[2358] 6 Tr 4547.
[2359] 3 Tr 2551.
[2360] 6 Tr 4555-4556.

that using authorized ROEs as a substitute ignores investors' return expectations.[2361] Mr. Bandyk, who did not present any risk premium analysis results, argues that Consumers' risk premium analysis results should not be considered because this calculation relies on ROEs set by other regulatory commissions, which is circular and unlikely to result in returns set by financial methodology.[2362]

Ms. Bulkley counters, in part, that it is unreasonable to suggest that investors do not consider authorized ROEs in their assessment of the value of a utility stock.[2363]

This PFD finds that Staff's, the Attorney General's and CUB's reasoning to reject a risk premium analysis based on authorized ROEs (as opposed to based on realized ROEs) is persuasive. This PFD notes that FERC has rejected the risk premium model that relies on previous ROE determinations as circular.

> While all models, including the DCF, feature some circularity, such circularity is particularly direct and acute with the Risk Premium model because it directly relies on past Commission ROE decisions. As a result, we share the concerns expressed by various parties that the circularity inherent in the Risk Premium model's use of prior ROE determinations would largely continue previously-approved ROEs and reflect past circumstances that influenced the previous ROE decisions.[2364]

This PFD also notes that the Commission recently found DTE Gas' risk premium model was inflated as "the company's risk premium model employs the use of approved ROEs, which provides a limited data set as opposed to Staff's model that utilizes earned

---

[2361] 3 Tr 2552-2553.
[2362] 6 Tr 3970.
[2363] 4 Tr 2901.
[2364] FERC Opinion 569, par. 343. This PFD notes that FERC subsequently concluded that the risk premium model, with certain modifications, was appropriate to use to estimate a reasonable ROE. See, FERC Opinion 569-A. However, this PFD also notes that on appeal, the Court of Appeals set aside FERC Opinion 569-A as FERC failed to offer a reasoned explanation for its reversal after having found the risk premium model "quite defective." See, MISO Transmission Owners v FERC, 45 F.4th 248 (CA DC Cir 2022).

ROEs."[2365] Accordingly, this PFD finds that Consumers' and ABATE's risk premium results which are based on authorized ROEs should be given little weight.

The parties take issue with other aspects of the models used by other parties and the inputs therein. However, these differences do not appear to change the results as significantly as the differences discussed above. Moreover, these other differences do not demonstrate that one approach necessarily is more accurate or meaningful than another approach. This PFD notes that the Commission has long recognized that the determination of a fair and reasonable ROE "is not subject to mathematical computation with scientific exactitude but depends upon a comprehensive examination of all factors involved."[2366] Thus, this PFD concludes that these other differences regarding the appropriate use of other, different models and inputs need not be resolved in this case, and that the results of these other models which use different inputs shall be considered, except as otherwise noted.

In sum, the average of the accepted ROE estimates generated by the parties' model results are as follows:

Party	Average	Range
Consumers	10.83%	10.40% - 11.26%[2367]
Staff	9.80%	8.98% - 10.34%[2368]
Attorney General	9.80%	9.57% - 9.98%[2369]
ABATE	9.34%	9.11% - 9.57%[2370]
CUB	8.53%	8.11% - 8.96%[2371]

[2365] Case No. U-21291, Order, November 7, 2024, p. 107.
[2366] *Meridian Twp v City of East Lansing*, 342 Mich 734, 749, 71 NW2d 234 (1955).
[2367] 4 Tr 2799; Ex. A-206 DCF (adjusted), ECAPM and Risk Premium rejected.
[2368] 6 Tr 4549; Ex. S-4, D-5, p. 14 DCF (adjusted), CAPM (avg), Risk Premium (avg)
[2369] Ex. AG-37, Ex. AG-38, Ex. AG-39.
[2370] 6 Tr 3786, 3804 DCF (avg), CAPM (avg), Risk Premium rejected

The combined average of these averages is 9.66%, with a range of 8.53% -- 10.83%.

Consumers, Staff, the Attorney General, ABATE and Walmart each offered evidence of recently authorized ROEs for utilities across the country.

Mr. Megginson states that the average authorized ROE decision for 2021 was 9.38%, for 2022 was 9.54%, for 2023 was 9.60%, for 2024 was 9.74%, and through June of 2025 was 9.68%, and that the full four-year average ROE (2021-2024) is 9.57%.[2372] Mr. Coppola states that the majority of the 50 ROE decisions in the year ended June 2024 and the 46 decisions in the year ended June 2025 are at rates well below 9.90%, with the few higher rates being primarily from regulatory commissions in California (wild fires and earthquakes), Florida (hurricanes), smaller utilities or those with unique geographical challenges (AL), and Michigan.[2373] He adds that for most of the other electric utilities that have business and financial risks comparable to Consumers operations, the ROE rates have averaged around 9.5% to 9.6% in the past two years, and that the average ROE rate during the two years ended June 2025 for the utilities in his peer group is 9.57%.[2374] Mr. Walters states that authorized ROEs for both electric and gas utilities have declined over the last 10 years and have been below 10.0% for about the last nine years.[2375] He adds that the majority of authorized ROEs since 2016 have been below 9.7%, with many being below 9.5%.[2376] Mr. Lyons states that according to data from S&P Global Market Intelligence, the average of the 104 reported electric utility rate case ROEs authorized by commissions to investor-owned

---

[2371] 6 Tr 3955 DCF (avg), CAPM (avg)
[2372] 6 Tr 4548; Ex. S-4, Sch. D-5, p. 13.
[2373] 3 Tr 2554; Ex. AG-40.
[2374] 3 Tr 2555; Ex. AG-41.
[2375] 6 Tr 3747-3748, Figure CCW-1.
[2376] 6 Tr 3749, TABLE CCW-1..

utilities since 2023 is 9.68%, while the range of reported authorized ROEs for the period is 8.63% to 11.45%, and the median authorized ROE is 9.70%.[2377]

In her rebuttal testimony, Ms. Bulkley states that previously authorized ROEs provide a "range of reasonableness" and benchmark that investors consider in assessing the authorized ROE of one utility against the returns available from other regulated utilities with comparable risk.[2378] She adds that it is important to screen this data to consider only the returns that have been authorized for risk-comparable companies and to consider the overall market conditions that existed at the time that the decisions were made.[2379] Later, in criticizing Mr. Bandyk's consideration of Consumers' currently authorized ROE in informing his recommended ROE – which consideration she asserts Mr. Bandyk suggested should not be made[2380] -- she states that she disagrees with his approach, asserting 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."[2381]

Nonetheless, Ms. Bulkley analyzed recently authorized ROEs and concludes that "over the past five years, authorized ROEs for vertically integrated electric utilities have increased", based on her compiled average ROEs of 9.57% for 2021, 9.75% for 2022, 9.72% for 2023, 9.79% for 2024, and 9.72% for 2025.[2382]

Ms. Bulkley disagrees with the evaluations conducted by Staff, the Attorney General, and ABATE, asserting that they reviewed ROEs for transmission and

---

[2377] 3 Tr 2610; Ex. WAL-3.
[2378] 4 Tr 2802-2803.
[2379] 4 Tr 2803.
[2380] 4 Tr 2806
[2381] 4 Tr 2910-2911.
[2382] 4 Tr 2804, Figure 3.

distribution-only electric utilities, which ROEs should be excluded from consideration.[2383] She adds that while Mr. Megginson references an average ROE from 2021 through June 2025, he fails to consider that the interest rate environment was significantly lower throughout 2021 and most of 2022.[2384]

While her criticism of the evaluations made by Staff, the Attorney General and ABATE – that these may include authorized ROEs for transmission and distribution-only electric utilities – is fair as far as it goes, this PFD notes that Ms. Bulkley does not identify those utilities that she believes should be excluded from their compilations or offer adjusted ROE percentages which exclude those utilities. Moreover, Ms. Bulkley's separate assertion -- that Mr. Megginson's failure to consider the lower interest rates for 2021 and 2022 is meaningful -- is contradicted by the fact that she offers averages for those same years without qualification.[2385]

In addition, this PFD finds that the results of Ms. Bulkley's own evaluation of past authorized ROEs are unsupported. While Ms. Bulkley offers a range of authorized ROEs for 2021-2025, unlike the other parties, she does not include an exhibit with a list of the Moreover, Ms. Bulkley's evaluation approach of past-authorized ROEs offered in her rebuttal testimony is inconsistent with the evaluation approach she followed in her direct testimony. In her rebuttal testimony, she used data from a different source (S&P Capital IQ Pro) than the source (RRA) she used in her direct testimony when calculating prior authorized ROEs for inclusion in her risk premium analysis.[2386] Similarly, for her evaluation in her rebuttal testimony, Ms. Bulkley used different, more expansive

[2383] 4 Tr 2804.
[2384] 4 Tr 2805.
[2385] 4 Tr 2804.
[2386] 4 Tr 2804, n. 17; 4 Tr 2750

screening criteria for the ROEs she used in her calculation than the screening criteria used for her risk premium analysis.[2387] Ms. Bulkley does not offer any explanation for changing her evaluation approach.

Finally, Ms. Bulkley's assertion that her range of authorized ROEs shows that over the last five years "authorized ROEs have increased" is misleading at best. While her averages for years 2022-2025 are greater than her average for 2021, her averages for those years show that the authorized ROEs have fluctuated up and down every year during that period, with the average for 2025 being at or below the averages for the prior three years.

This PFD finds that consideration of recently authorized ROEs is appropriate. The Commission has previously considered other ROEs and has stated that it will continue to do so.[2388] In addition, the Supreme Court's standards provide that equity returns should be "commensurate with returns on investments having corresponding risks" and other regulated utilities are enterprises with the most closely corresponding business model risks to those of Consumers.[2389]

This PFD agrees with Staff that the ROE authorizations from utility rate cases in the United States are pertinent as a "reasonable measuring stick" with which to compare ROE model results.[2390] This PFD also agrees with Ms. Bulkley 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

---

[2387] 4 Tr 2803; 4 Tr 2750, n. 35.
[2388] See Case No. U-20940, Order, December 9, 2021, p. 89, 91 ("[T]he Commission notes that it will continue to compare ROE for DTE to other approved benchmarks including . . . the approved ROEs for comparable utility peers.").
[2389] *Hope*, *supra*, at p. 603.
[2390] 6 Tr 4548

effect."[2391] Similarly, this PFD agrees with Mr. Bandyk that "we cannot look to other jurisdictions to determine the opportunity cost for investors," as an ROE can be set below the national average for authorized ROEs and still be above the cost of equity.[2392]

This PFD finds that the average of recently authorized ROEs from other states is between 9.50% -- 9.60% and are trending lower.

While the results of the models used to estimate a reasonable ROE are in the range of the recently authorized ROEs throughout the country, these ROE estimates are contrary to the Supreme Court standards which provide that the setting of a fair and reasonable return for regulated utilities is determined by the business risk applicable to the regulated utility industry. *See, Wilcox*, *supra*, (In determining the "rate of compensation" which is sufficient for capital invested in business enterprises, "the amount of risk in the business is a most important factor" and "the rate expected and usually realized there upon investments of a somewhat similar nature with regards to the risk attending them."); *Bluefield, supra*, ("A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally made . . . on investments in other business undertakings which are attended by corresponding risks and uncertainties."); *Hope, supra*, ("By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.").

The Supreme Court described the nature of the business model risk (or lack thereof) relevant to establishing a reasonable return as being based upon public utilities

---

[2391] 4 Tr 2910-2911.
[2392] 6 Tr 3953.

selling a necessary product – energy, power, light, heat – without competition pursuant to a state regulated monopoly.

> In an investment in a gas company such as complainant's, the risk is reduced almost to a minimum. It is a corporation which monopolizes the gas service of the largest city in America, and is secured against competition under the circumstances in which it is placed.[2393]

Standard & Poor's description of the lack of risk for regulated utilities mirrors that of the Supreme Court, with S&P stating that the regulated utility industry is "very low risk" as it "provides indispensable services that are strategically important to economies, have material barriers to entry, and essentially operate as a monopoly insulated from market challenges."[2394]

In describing the connection between the business risk and the expected return, the Supreme Court incorporated the fundamental economic risk/reward principle, stating:

> The less risk, the less right to any unusual returns upon the investments. One who invests his money in a business of a somewhat hazardous character is very properly held to have the right to a larger return, without legislative interference, that can be obtained from an investment in government bonds or other perfectly safe security.[2395]

See, also, Bluefield, supra (A public utility "has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures.")

[2393] *Wilcox, supra*.
[2394] See, Case No. U-20836, 8 Tr 3065, quoting S&P RatingsDirect: DTE Electric Co., September 8, 2021. This characterization of the low-risk nature of the regulated industry was expressly affirmed by the Commission in that case. See, Order, November 18, 2022, p. 231, 241: PFD, September 19, 2022, p. 449-450.
[2395] *Wilcox, supra*.

Indeed, the Supreme Court made clear that establishing a reasonable ROE is not a function of making sure that the utility is profitable. *See, Hope, supra* ("Regulation does not ensure that the business shall produce net revenues.")

Thus, while under the Supreme Court standards regulated utilities are entitled to a return that is commensurate with returns on investments in other enterprises having corresponding risks – such as other regulated utilities[2396] -- regulated utilities are not entitled to returns commensurate with or more than returns on investments in other enterprises having greater risks – such as the riskier businesses in the general market. As such, the Supreme Court standards require that authorized ROEs be set at a level of returns which are less than the returns for the general market.

In this case, Mr. Bandyk articulated the contradiction between the range of recently authorized ROEs and the Supreme Court standards applicable to setting fair and reasonable ROEs.

> A higher return implies higher risk, so approving ROEs that are higher than market returns would imply that regulated utilities are riskier investments than the market as a whole. But they are not. Regulated utility returns tend to be less risky than the market as a whole, indicating that regulatory decisions are not in line with the economic reality that lower risk means lower return.[2397]

Moreover, Mr. Bandyk presented evidence in support of this contradiction.[2398] This PFD notes that Mr. Bandyk's testimony on this question is consistent with that which he provided in Consumers' 2023 electric rate case:

> Mr. Bandyk offered compelling evidence that the average ROEs for regulated electric and gas utilities awarded by public regulatory

---

[2396] Ms. Bulkley states that utilities "compete directly for capital with other investments of similar risk, which include other electric, natural gas, and water utilities nationally." 4 Tr 2722.
[2397] 6 Tr 3950.
[2398] 6 Tr 3948-3951.

> commissions over the last 30 years have been consistently above the average ROE for all U.S. stocks by about two percentage points and are projected to continue to be so.1509 This evidence is directly material to the first Supreme Court standard that "the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests", that the return to the utility's shareholders should be commensurate with returns on investments in other enterprises having "corresponding risks", and that the utility has "no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures."1510 As Mr. Bandyk correctly asserted, since a higher return implies higher risk, the fact that awarded ROEs are higher than general market returns implies that regulated utilities are riskier investments than the market as a whole, when regulated utilities are not riskier. Rather, "[r]egulated utilities are less risky than competitive industries, and therefore supposed to produce a lower total return."[2399]

Ms. Bulkley purports to rebut Mr. Bandyk's testimony and credibility on this point but her attempts are unsupported and misleading.

Proclaiming her "fundamental disagreement" with Mr. Bandyk, Ms. Bulkley asserts that Mr. Bandyk "has provided no evidence" that supports his position that regulatory commissions have "consistently erred" in establishing utility ROEs, and that "there is no evidence" that regulatory commissions have been consistently approving "unjust and unreasonable rates."[2400] Ms. Bulkley then offers considerable testimony attempting to rebut the non-existent evidence.[2401]

In support of her assertion that there is "no evidence" that Mr. Bandyk's estimate of the cost of equity is reasonable, Ms. Bulkley states that the results of his CAPM analysis (8.11%) are "substantially lower than any ROE that has been authorized by a regulatory commission in the past."[2402] However, Ms. Bulkley provides no citation or

---

[2399] Case No. U-21389, PFD, December 21, 2023, pp 357-58 (citations omitted).
[2400] 4 Tr 2807, 2808.
[2401] See, 4 Tr 2806-2808, 2813-2816.
[2402] 4 Tr 2807-2808. Ms. Bulkley also stated that Mr. Bandyk's average CAPM estimate is "substantially below any authorized ROE for a natural gas or electric utility since at least 1980." 4 Tr 2797.

reference in support of her broad statement. Moreover, her statements are directly contradicted by evidence submitted in each of Consumers' last two electric rate cases, which show authorized ROEs of 8.57% and 8.70% in 2021, 8.57% and 7.85% (2x) in 2022, and 8.72% and 8.91% in 2023.[2403]

In expressing her concerns regarding the article from Public Utilities Fortnightly by Steve Huntoon, which Mr. Bandyk references and which article she acknowledges states that commissions have set authorized ROEs at rates that are "not consistent to utilities' risk level," Ms. Bulkley argues that Mr. Huntoon "is not a cost of capital expert" and that the article "is merely his opinion."[2404] In this regard, Ms. Bulkley apparently is suggesting, albeit without any explanation, that Mr. Huntoon's opinion is somehow categorically less material or relevant than the opinions offered by the authors of the materials and studies upon which she relies in support of her opinions. Moreover, her implication that his opinion is unsupported is contradicted by the article itself, which includes the following supporting statements (which themselves are supported): a) Utility stocks have outperformed the broader market over the last 12 years, and b) Jack Bogle, the founder of Vanguard, provides rigorous analysis that the long-term total return for the broader market will be around 7% going forward, c) Professor Burton Malkiel corroborates the 7% in the latest edition of his seminal work, d) This performance shows that less risky utilities are being awarded much higher returns – approximately 40% higher – than the broader market is expected to return, and e) Utility stocks are the only stocks where Wall Street analysts actually set the earnings instead

[2403] Case. No. U-21389, Ex. AG-1.22; Case No. U-21585, Ex. AG-1.21.
[2404] 4 Tr 2816. Citation omitted.

of just forecasting earnings, as utility regulators use Wall Street analysts' forecast of earnings and dividend growth to determine the allowed return on equity.[2405]

Using a reference included within the article, Ms. Bulkley asserts that the fact that the return generated by Vanguard's utility exchange-traded fund has significantly lagged behind the S&P 500 Index "refutes Mr. Bandyk's claims that utilities violate 'the economic reality that lower risk means lower return.'"[2406] Ms. Bulkey's assertion is problematic. Mr. Bandyk did not claim that "utilities" violate the economic reality that lower risk means lower return; rather, Mr. Bandyk stated was that "regulatory decisions" are not in line with "the economic reality that lower risk means lower return."[2407]

Ms. Bulkley asserts that the Minnesota Public Service Commission specifically disagreed with Mr. Bandyk's position that there is a substantial difference between authorized ROEs and the cost of equity for utilities, quoting from a 2023 order.[2408] However, the quote doesn't support what Ms. Bulkley says it does; rather, the quote concerns the issue of the reliability of a multi-stage DCF analysis to forecast the long-term cost of equity. Moreover, as MNSC points out, Ms. Bulkley's quote was selective and thus misleading.[2409]

Ms. Bulkley's attempts to undermine the credibility of Mr. Bandyk's testimony are unavailing. This PFD finds that Mr. Bandyk's testimony – like those of Messrs. Megginson, Coppola and Walters – is well-reasoned, consistent and well-supported.

[2405] Steve Huntoon, "Nice Work If You Can Get It", *Public Utilities Fortnightly*, August, 2016, p. 2. Ms. Bulkley notes that Mr. Bandyk did not provide the article as the article is behind a paywall. However, this article was admitted into evidence in Consumers' 2023 electric rate case. See, Case No. U-21389, Ex. MEC-7, Dkt. No. 0355.
[2406] 4 Tr 2816, citing 6 Tr 3950.
[2407] 6 Tr 3950.
[2408] 4 Tr 2808.Citation omitted.
[2409] MNSC initial brief, p. 44-45.

As indicated, the Supreme Court standards provide that regulated utilities are entitled to a return that is commensurate with the returns earned by other businesses with corresponding risks (i.e., other regulated utilities) but are not entitled to returns commensurate with or higher than businesses having greater risks (i.e., publicly traded businesses in the general market). Thus, the Supreme Court standards require that authorized ROEs be set at a level of returns which are less than the expected returns for the general market.

In that regard, this 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%.[2410]

Similarly, Mr. Walters provided the long-term market expectations of several financial institutions, as follows:

BlackRock Capital Management	10 Years	6.70%
JP Morgan Chase	10 - 15 Years	6.70%
Vanguard	10 Years	2.8% - 4.8%
Research Affiliates	10 Years	3.92%
Invesco	10 Years	5.0% - 6.3%
Goldman Sachs	10 Years	3.00%
Fidelity	20 Years	5.70%
Schwab	10 Years	6.00%[2411]

[2410] Michigan Public Service Commission, Case No. U-21870, Official Notice of Facts, October 3, 2025.
[2411] 6 Tr 3801, Table CCW-9. Citations Omitted.

Ms. Bulkley rebuts the notice of facts figure (but not Mr. Walters' figures) in two respects. First, she expresses "concerns" that "studies" have shown that investment firms have not accurately forecasted actual returns, and that there is a "significant degree of uncertainty" associated with their forecasts estimates.[2412] However, Ms. Bulkley does not cite any such studies, relying solely on an article from a competing investment management firm advocating that investors should consider working for them because they don't make forecasts. It is noted that Ms. Bulkley does not provide or reference any other forecasts with different projections.

Second, Ms. Bulkley states that she made her own estimate of the expected market return on equity for the broader stock market. Based on an estimated market capitalization-weighted S&P 500 dividend yield of 1.36% and a weighted long-term S&P 500 growth rate of 11.15%, she asserts that the estimated required market return for the S&P 500 Index at the time of her direct testimony was 12.58%, and that based on more recent data through September 2025, the estimated market return for the S&P 500 is 13.34%.[2413] However, Ms. Bulkley's use of the S&P 500 for her yield, growth rates and market return results in an unreliable and inflated estimate for the expected market return for the broader stock market.

Ms. Bulkley acknowledges that the S&P 500 Index "is composed of the largest top-performing companies", such that "it is reasonable to assume the index will always contain individual companies with projected earnings growth rates that will be considered high."[2414]

[2412] 6 Tr 2801.
[2413] 4 Tr 2800-2801, citing Ex. A-14, Sch. D-5, p. 16-21; Ex. A-206, p. 15-20.
[2414] 4 Tr 2865.

Mr. Coppola adds that many large technology companies with high growth prospects in the S&P 500 Index have a larger than normal weighting in the calculation of the return due to their relatively large market capitalization.[2415]

Mr. Walters also states that because the S&P 500 is a market capitalization weighted index, companies with larger market capitalizations have a greater impact on the index's overall performance.[2416] He adds that S&P's 500's strong performance in 2023 and early 2024 was largely driven by a small group of "mega-cap" companies known as the Magnificent 7, with those seven stocks accounting for a majority of the S&P 500's returns even though there were 493 other companies in the index.[2417] Most significantly, Mr. Walters quotes from an S&P Dow Jones Indices report for April 2024 as follows:

> Year-to-date, the S&P 500 remained up 5.57% (with 10 of the 11 sectors up; Real Estate was down 9.86%), as breadth declined but remained positive (302 up and 199 down, compared to last March's 369 and 134 YTD, respectively). The Magnificent 7 as a group still dominated, accounting for 51% of the index return (which included Apple's 11.5% YTD decline and Tesla's 26.2% YTD decline), as NVIDIA (up 74.5% YTD) represented 41% of the S&P 500's YTD gain.[2418]

This PFD notes that while the group of seven stocks (Magnificent 7) accounted for 51% of the S&P 500 Index return, a single Magnificent 7 company (NVIDIA), which was up 74.5% YTD, accounted for 41% of the S&P 500 Index's YTD gain."[2419]

This PFD finds that this evidence unequivocally shows that the return for the S&P 500 Index is overwhelmingly influenced and inflated by a very few extremely profitable

---

[2415] 3 Tr 2547.
[2416] 6 Tr 3764-3765.
[2417] 6 Tr 3764.
[2418] 6 Tr 3765. Citation omitted.
[2419] 6 Tr 3765. Citation omitted.

companies with returns that Supreme Court specifically stated regulated utilities are not entitled to. *See, Bluefield, supra* (A public utility has "no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures.") Thus, it is unreasonable to calculate the projected return for the general market – against which return a reasonable ROE will be determined – based on the S&P 500 Index whose return is exceedingly inflated by a few "highly profitable" companies.

The second Supreme Court standard for establishing a reasonable return on equity is that the return should be "sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[2420] This PFD finds that the record evidence in this case supports a finding that the ROEs proposed by Staff, the Attorney General, ABATE, and CUB, and the ROE recommended in this PFD are each more than sufficient for Consumers to maintain its credit and attract capital.

The financial integrity of Consumers' business and its ability to maintain its credit and attract capital are directly a function of Consumers' lack of risk as an operating regulated utility.

Again, like the Supreme Court, S&P states that the regulated utility industry is "very low risk" as it "provides indispensable services that are strategically important to economies, have material barriers to entry, and essentially operate as a monopoly insulated from market challenges."[2421]

[2420] *Hope*, 320 U.S. at 603.
[2421] See Case No. U-20836, Order, November 18, 2022, p. 231, 241; PFD, September 19, 2022, p. 449-450, quoting 8 Tr 3065.

Commensurate with the low risk nature of the regulated utility industry, Consumers' current credit ratings from the three main credit reporting agencies – Moody's, S&P, and Fitch – have consistently been within the middle of the multiple levels of ratings categories, with each level of ratings category being "investment grade." Ms. Bulkley states that Consumers Energy currently has an investment-grade long-term rating of A- from S&P and A3 from Moody Investors Service's ("Moody's").[2422] Similarly, Mr. Megginson states that S&P rates Consumers Energy's senior secured debt "A", which was raised from "A-" on December 4, 2014; Moody's rates Consumers senior secured debt "A1", which was lowered from "Aa3" in May 2021; and Fitch rates Consumers senior secured debt "A+", which was raised two notches from "A-" in March 2016.[2423] He adds that S&P has held Consumers' credit rating steady for approximately 10 years and Fitch has held it steady for over eight years, with Moody's one notch downward revision from Aa3 (equivalent to S&P's AA- rating) in 2021 put Consumers' credit rating more in line with the other two agencies ratings.[2424]

"Investment grade" refers to the group of credit ratings that indicate a low default risk.[2425] As such, companies with a rating in this range will issue debt at a lower interest rate than others with a poorer credit rating, allowing them to obtain financing more cheaply.[2426] More significantly, as the term suggests, companies within this rated grouping are each suitable for "investment purposes", including for the attraction of capital through stock and bond issuances and maintaining credit through borrowing

[2422] 4 Tr 2734. Citation omitted.
[2423] 6 Tr 4524; Ex. S-4, Sch. D-5, p. 3.
[2424] 6 Tr 4524-4525.
[2425] See, Bankinter Financial Dictionary, Investment grade.
[2426] Id.

from lenders. Indeed, the Commission has previously recognized that a credit rating in the middle levels of investment grade companies is a strong credit rating. See, Case No. U-20940, Order, December 9, 2021, p. 78 ("The Commission finds that the new Moody's rating [for DTE] places the company six notches above the lowest investment grade rating, which is still a healthy credit rating.").

In addition, the credit rating averages for the proxy group companies further support the solid creditworthiness of the utility industry generally, and of Consumers specifically. Mr. Megginson states that his proxy group's average S&P credit rating is (BBB+), which is two notches below Consumers credit rating of (A), and Moody's average credit rating for the group is (Baa1), which is three notches below Consumers credit rating of (A1).[2427] Thus, he asserts that Consumers has a much higher credit rating and is considered a better credit risk, i.e., safer company than the proxy group.[2428] Similarly, Mr. Walters states that the proxy group has average credit ratings of BBB+ and Baa2 from S&P and Moody's, respectively, with the proxy group's average rating of BBB+ from S&P being one notch lower than Consumers Energy's rating of A- from S&P and the proxy group's average rating of Baa2 from Moody's being two notches lower than Consumers Energy's rating of A3 from Moody's.[2429] Noting that Consumers Energy currently has an A- long-term credit rating from S&P, Mr. Bandyk adds that that rating is higher than the ratings for all but 5 of the 19 proxy group companies.[2430]

[2427] 6 Tr 4540.
[2428] 6 Tr 4540-4541; Ex. S-4, Sch. D-5, p. 2.
[2429] 6 Tr 3773-3774; ex. AB-6.
[2430] 6 Tr 3972.

Regarding Mr. Walters's and Mr. Bandyk's assessment of the relative risk of Consumers based on relative credit rating comparisons, Ms. Bulkley states that she disagrees 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 [Consumers'] equity."[2431] She adds that "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."[2432] She argues that, because the proxy companies do not have exactly the same risk profile as the subject company, it is reasonable to compare the relative risks of the proxy group companies and the subject company "to determine the appropriate placement of the ROE within the range of results established using the proxy group companies."[2433] In this regard, she concludes that Consumers has "slightly greater regulatory and business risk than the proxy group."[2434]

Ms. Bulkley's argument is problematic and inconsistent. While Ms. Bulkley states she disagrees with the use of credit ratings to assess Consumers' risk as compared to the proxy group, she uses those same S&P credit ratings to assess comparable risk in formulating her proxy group and to apply her screening criteria to select companies that have "investment grade" long-term ratings, with Ms. Bulkley's stating that her proxy companies "all possess a set of operating and risk characteristics that are substantially comparable to the Company, and thus provide a reasonable basis to estimate the

[2431] 4 Tr 2914
[2432] Id.
[2433] 4 Tr 2915.
[2434] Id.

appropriate cost of equity for the Company."[2435] Ms. Bulkley's assertions about the use of credit ratings are also contradicted by Mr. Bleckman, who states that Consumers' access to capital markets and its ability to raise capital at competitive rates "is largely based on Consumers' credit quality as determined by credit rating agencies."[2436]

Although Ms. Bulkley asserts that Consumers' level of capital expenditures gives it higher risk relative to the proxy group, she acknowledges that credit rating agencies recognize the risks associated with significant capital expenditures.[2437] Similarly, Ms. Bulkley suggests that Consumers' has greater risk than her proxy companies due to Michigan's regulatory environment, despite acknowledging that both S&P and Moody's consider regulatory risk in establishing a company's credit rating.[2438] In that regard, Mr. Megginson notes that in Moody's May 29, 2025, ratings report, the agency stated "[W]e view the regulatory framework in Michigan to be more credit supportive than most other states.[2439] Thus, as Mr. Bandyk states, these asserted risks have already been accounted for in Consumers' credit rating, such that Consumers is not at a higher risk than the proxy group.[2440]

Moreover, the market for long-term debt has been receptive to utility issues of debt. Mr. Megginson states that Consumers issued $700 million of secured debt in July 2024 at a very favorable rate and credit spread.[2441] Mr. Coppola states that the market for new utility debt issues has been very robust with over 400 new issues completed in

---

[2435] 4 Tr 2734-2735; Ex. A-14, Sch. D-5, p. 2.
[2436] 3 Tr 873-874.
[2437] 4 Tr 2758.
[2438] 4 Tr 2763.
[2439] 6 Tr 4525. Citation omitted.
[2440] 6 Tr 3971-3972.
[2441] 6 Tr 4527, citing Ex. A-28.

2023 and 2024.[2442] He adds that several electric utilities that have accessed the capital markets at competitive interest rates since receiving ROEs near or below the average rate of 9.50%.[2443] Mr. Walters states that capital investments for the utility industry continue to stay at elevated levels, which is clear evidence that these capital investments are attracting both equity and debt capital to the utility industry in a manner that allows for funding these elevated capital investments.[2444]

Mr. Bleckman asserts that a high degree of volatility and economic uncertainty has emerged in recent months with respect to financial markets, interest rates, and geopolitical tensions, and that during this period of heightened risk and volatility, it will be critical for the Consumers to have an authorized ROE and equity ratio that is supportive of its good credit quality.[2445] Similarly, Ms. Bulkley states she bases her ROE recommendation on 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."[2446] However, Consumers' reliance on other factors such as market conditions or company-specific risks are misplaced.

First and foremost, the Supreme Court standards provide that the relevant risk for purposes of establishing a reasonable ROE relates to the business model risk (or lack thereof) of regulated utilities selling a necessary product without competition from other sellers, and not on any risk differences among different regulated utilities. See, discussion, *supra*. Indeed, the Supreme Court standards make clear that the

---

[2442] 6 Tr 2562; Ex. A-28.
[2443] 3 Tr 2559; Ex. AG-40.
[2444] 6 Tr 3752, Figure CCW-2. Citation omitted.
[2445] 3 Tr 879, 880.
[2446] 4 Tr 2794.

determination of a reasonable ROE is not based on ensuring that the utility is profitable. Rather, a reasonable return should be adequate to support its credit while operating under "efficient and economical management", and that "regulation does not insure that the business shall produce net revenues."[2447] As such, the relevant risk under the Supreme Court standards is a function of the business model of the regulated utility industry as a whole, and does not involve consideration of company specific risks.

Moreover, Ms. Bulkley acknowledges that the cost of equity models take into account the capital market conditions.

> Capital market conditions influence cost of equity models by affecting inputs in the model at the time the analysis is performed. While the ROE that is established in a rate proceeding is intended to be forward-looking, the analyst uses current and projected market data, specifically stock prices, dividends, growth rates and interest rates, in the models to estimate the required return for the subject company.[2448]

As such, there is no reason to further adjust the model results to again account for market conditions.

In addition, adverse or changing market conditions generally do not affect regulated utilities generally do not affect regulated utilities as much as other business enterprises. As Mr. Coppola states, utility stocks are a safe-haven for investors during times of uncertainty and volatility because they are not as susceptible to volatility as the general stock market, which is reflected in the average Beta value of 0.76 of the utility peer group in contrast with the general stock market value of 1.0.[2449] Similarly, noting the "defensive characteristics of regulated utilities", Mr. Walters states that utilities are often viewed by investors as safer assets during times of macroeconomic and

[2447] *Bluefield, supra; Hope, supra.*
[2448] 4 Tr 2725.
[2449] 3 Tr 2562.

geopolitical uncertainty.[2450] Indeed, Mr. Bandyk states that regulated utilities are protected from market risks.

> The ability to recover costs inoculates rate-regulated utilities from systematic risk. Rate regulation protects investor-owned utilities like Consumers Energy from the risks of rising expenses, commodity price risk, and competitive risks, and they enjoy natural monopolies that mitigate market risks associated with the customer base. For example, commodity prices tend to be passed through directly to customers, and utilities can request a rate increase if sales decline.[2451]

Mr. Bleckman states that a key financial metric used by rating agencies is the ratio of Funds From Operations ("FFO") to Debt ("FFO/debt ratio"), and that there needs to be a balance between Consumers' equity ratio and ROE that will ensure that this financial metric does not degrade and cause significant credit deterioration.[2452] He asserts that recent rate cases have resulted in a sharp decline in rate of return (ROE multiplied by equity ratio), which in turn lowers Consumers' cash flow and FFO/debt ratio, and that these "negative credit metric impacts" puts Consumers' "credit quality and credit ratings at risk."[2453] However, when asked in discovery what the sufficient FFO/debt ratio is, he responded that this ratio was not available because a calculation of the FFO/debt ratio is "not feasible" using only a proposed equity ratio and ROE."[2454] As such, Mr. Bandyk states that if he has not calculated the FFO/debt ratio, Mr. Bleckman cannot possibly know if the FFO/debt ratio resulting from the proposed equity

---

[2450] 6 Tr 3765.
[2451] 6 Tr 3964.
[2452] 3 Tr 818.
[2453] 3 Tr 821.
[2454] 6 Tr 3978.

ratio and ROE would be "sufficient" toward preserving Consumers' credit rating, or if a lower equity ratio and/or ROE would be insufficient.[2455]

Moreover, Mr. Coppola notes that the most recent Moody's credit report for Consumers shows that Consumers' FFO/debt ratios for the last few years are all above the 18% downgrade threshold.[2456]

This PFD agrees that a change to the authorized ROE likely will alter Consumers' credit metrics. However, that a change in the authorized ROE will change Consumers' credit metrics does not mean that any such change to the ROE should not occur. As FERC has stated,

> Although any rate reduction, by reducing earnings, will necessarily adversely affect certain financial metrics, that does not preclude the Commission from reducing rates. It is not incumbent on the Commission to demonstrate that any rate reduction, if supported by evidence demonstrating reduced cost of capital, would not adversely affect utilities' financial metrics. By the logic of certain parties, virtually any rate reduction would be unjust and unreasonable simply because it reduces the ROE and thus harms financial metrics for the affected utilities.[2457]

Moreover, even if a change in the ROE might lead to a credit rating downgrade, Consumers' credit rating will remain within the upper to middle levels of investment grade credit ratings, which ensures the maintenance of its credit and its ability to attract capital. Indeed, the credit ratings for Ms. Bulkley's proxy group, which she says possess "operating and risk characteristics" that are "substantially comparable" to Consumers, show that Consumers' S&P credit rating is several notches above 14 of the 19 companies in her original proxy group.[2458] Thus, even if a reduction to the authorized

---

[2455] Id.
[2456] 3 Tr 2516-2517, citing Ex. AG-47 Confidential.
[2457] FERC Opinion 569-A, 171 FERC 61154, (2020) par. 44.
[2458] Ex. A-14, Sch. D-5, p. 2.

ROE results in Consumers' credit rating being downgraded one or even two notches – and there is no evidence presented in this case that such a downgrade would occur – Consumers' credit rating would remain two notches above 14 of the companies Ms. Bulkley included in her proxy group.

Ms. Bulkley asserts that another factor which impacts Consumers' overall credit risk profile are flotation costs, which she asserts must be considered when determining where a Consumers' ROE falls within the range of analytical results.[2459] Mr. Megginson counters that flotation cost enhancement to any of Consumers' ROE estimates should be rejected, reasoning that it would be improper to include flotation cost enhancement since Consumers, as a subsidiary of CMS Energy, does not own its own stock and thus does not incur flotation costs.[2460] This PFD agrees, noting that the Commission has rejected the recovery of flotation costs.

> The Commission also finds that the exclusion of flotation costs is appropriate. The Commission is persuaded that these costs are not costs incurred by the regulated utility. Consequently, it is not appropriate to include these costs in the calculation of Consumers' return on equity.[2461]

Mr. Bleckman states that Consumers has saved customers $152 million annually as a result of improved credit ratings and lowered interest costs.[2462] However, as MNSC states, Mr. Bleckman's exhibit (Ex. A-32) shows that the $152 million is the cumulative savings over 18 years, which savings is significantly offset by the savings – less rate payment totals – ratepayers would obtain with a reduced ROE.[2463]

[2459] 4 Tr 2752.
[2460] 6 Tr 4556.
[2461] Case No. U-14347, Order, December 22, 2005, p. 24.
[2462] 3 Tr 882, citing Ex. A-32.
[2463] MNSC initial brief, p. 35-36.

In conclusion, this PFD finds that the ROEs recommended by Staff, the Attorney General, ABATE and CUB are each reasonable and commensurate with returns for recently authorized regulated utilities, on investments having corresponding risks, while the ROE recommended by Consumers is not. However, this PFD finds that the ROEs recommended by the parties are not commensurate with or are less than the returns projected for riskier investments in companies in the general market. This PFD further finds that the ROEs recommended by Staff, the Attorney General, and ABATE, as well as the ROE recommended in this PFD are more than sufficient for Consumers to maintain its credit and attract capital, and that Consumers' recommended ROE is unnecessary to do so.

Given the recent level of authorized ROEs garnered in the regulated utilities industry, the Supreme Court standards require divergent and conflicting returns. On the one hand, this PFD finds that the results of the estimating models suggest that a reasonable ROE commensurate with the returns earned by other regulated utilities is about 9.7%. On the other hand, this PFD finds that a reasonable ROE less than the expected return earned by the riskier general market is about 6.7%. Thus, the optimal ROE which best aligns with the conflicting Supreme Court standards is an ROE of 8.2%, which is equally removed from fully complying with the standards.

Accordingly, this PFD recommends that the Commission adopt an ROE of 8.2%.

2. Long-Term Debt Cost Rate

Consumers originally proposed a long-term debt rate of 4.54%, with this rate being calculated starting with the debt issuances outstanding as of December 31, 2024, adding the planned new debt issuances in May 2025, August 2025, May 2026, and

August 2026, and assuming a spread of 138 basis points over the United States Treasury rate.[2464] Subsequently, Mr. Bleckman agreed with Staff's update to reflect the actual debt issuance costs for the May 2025 and August 2025 issuances.[2465] As such, and as Mr. Bleckman used the most current forecast of 30-year U.S. Treasury rates at the time of rebuttal, Consumers asserts that the Commission should adjust Consumers' original long-term debt rate down from 4.54% to 4.43%, which reflects the most current information available for all of the completed and planned long-term debt issuances through the test year in this case.[2466]

Staff recommends a long-term debt cost rate of 4.37%, which is based on lower cost rate projections for Consumers' $1.125 billion in May & August 2025 & $1.325 billion in May & August 2026 new debt issuances, as adjusted pursuant to a May 2025, issuance of $1.125 billion in debt at a cost rate substantially lower than what Consumers projected for its 2025 issuances, along with a lower issuance credit spread.[2467]

The Attorney General proposes a long-term debt cost rate of 4.39%, which 0.15% lower than Consumers' proposed rate, because Consumers 2025 debt issuances had lower costs than projected and because Mr. Bleckman assumed a rate for the 30-year U.S, Treasury bonds above the actual rates as of September 15, 2025.[2468]

This PFD finds that Mr. Bleckman's more current forecast should be used. As such, this PFD recommends that the Commission adopt Consumers' adjusted debt rate

---

[2464] Consumers initial brief, p. 291. Citations omitted.
[2465] Id.; 3 Tr 887.
[2466] Id., p. 293. Citations omitted.
[2467] Staff initial brief, p. 71. Citations omitted.
[2468] Attorney General initial brief, p. 164-165. Citations omitted.

of 4.43%, which reflects the most current information available for all of the completed and planned long-term debt issuances through the test year.

3. Short-Term Debt Cost Rate

Consumers proposed a short-term debt rate of 4.92% for the test year, which Staff and the Attorney General both adopted in their proposed capital structures.[2469] Thus, this PFD recommends that the Commission adopt Consumers' short-term debt cost rate.

Staff argues that Consumers' short-term debt facilities are "inefficiently used and costly to ratepayers," and thus requests that the Commission disallow all costs associated with Consumers' Scotiabank Revolver in future rate cases, arguing that the $250 million Scotiabank Revolver has never been used since its inception in 2018 and is substantially down in the pecking order of facilities to be used when necessary, and that Consumers has a more than adequate $1.1 billion JP Morgan Revolver at its disposal without the need for the unnecessary and expensive Scotiabank revolver.[2470] Staff asserts that disallowing costs associated with the Scotiabank Revolver would save ratepayers approximately $1 million per year.[2471]

Consumers counters that it is inappropriate for the Commission to consider or pre-decide issues of disallowances in future rate cases that are not currently before the Commission.[2472] Consumers argues that its short-term debt portfolio is a) appropriately sized and in line with peer utilities on average, b) required to support Consumers' robust capital investment plan and to meet growing short-term liquidity needs, c) a key

[2469] Consumers initial brief, p. 293; Staff initial brief, p. 72; Attorney General initial brief,
[2470] Staff initial brief, p. 72. Citations omitted.
[2471] Id.
[2472] Consumers initial brief, p. 296.

component of Consumers' credit quality and credit ratings, and d) reasonable, prudent, and beneficial to customers because it effectively minimizes liquidity risk.[2473] Regarding the Scotiabank Revolver, Consumers states that the Scotiabank Revolver is currently being used with multiple letters of credit issued against the facility, which letters are related to MISO, are critical financial instruments in conducting Consumers' ongoing business operations, and that the letters of credit associated with the Scotiabank Revolver cannot practically be moved to Consumers' JP Morgan Revolver.[2474]

This PFD finds that Consumers has complied with the Commission's directive 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".[2475] In this regard, Mr. Bleckman testified that at year-end 2024, Consumers' credit capacity is 5.3% in comparison to Consumers Energy's peer companies which maintained, on average, a ratio of revolving credit facilities to net Property Plant and Equipment of 5.4%.[2476] This PFD also finds that the Scotiabank Revolver is currently being used to meet Consumers' short-term liquidity needs. Regarding Staff's request that the costs for this Revolver be disallowed in future rate case, this PFD agrees with Consumers that it isn't appropriate for the Commission to adopt such a disallowance in future cases based on the record in this case. Accordingly, this PFD recommends that the Commission reject Staff's recommendation to disallow the cost of the Scotiabank Revolver in future rate cases.

[2473] Id. Citation omitted.
[2474] Id., p. 297.
[2475] Case No. U-21585, Order, March 21, 2025, p. 236; 3 Tr 848-854.
[2476] Consumers initial brief, p. 295, citing 3 Tr 852-853; Ex. A-39.

4. Other Cost Rates

Consumers, Staff and the Attorney General are in agreement that the cost rate for preferred stock should be 4.50%, and that the cost rates for the long-term debt, preferred stock, and common equity components of ITC should correspond to the cost rates established for long-term debt, preferred stock, and common equity, and the cost rates for other components should be zero.[2477] Exhibit A-14 (MRB-1), Schedule D-1, and Exhibit S-4, Schedule D-1. No other parties perform an analysis of this element of the Company's proposed capital structure. The cost rate proposed by the Company, and agreed to by Staff and the Attorney General, of 4.50% should be applied.

5. Overall Rate of Return

Based upon the foregoing discussion, this PFD recommends that the Commission adopt a balanced capital structure of 50% debt and 50% equity, along with a long-term debt cost rate, a short-term debt cost rate, and a return on equity as set forth herein, resulting in an overall rate of return which shall be set forth in the appendices which shall be filed in this docket on or before February 6, 2026.

VI.

ADJUSTED NET OPERATING INCOME

Net operating income (NOI) constitutes the difference between a company's operating revenue at current rates and its operating expenses including depreciation, taxes, and allowance for funds used during construction (AFUDC). Adjusted net

[2477] Consumers initial brief, p. 299, Staff initial brief, p. 72; Attorney General initial brief, p. 166. Citations omitted.

operating income (ANOI) includes the ratemaking adjustments to the recorded test year, NOI for projections, and disallowances.

A. Jurisdictional Revenues and Sales Forecast

1. Sales Forecast

Mr. Breuring presented Consumers' electric revenues, deliveries, generation requirements, and peak demands for the split-test year May 2026 – April 2027. Mr. Breuring described the process used to prepare the electric deliveries forecast as follows.

> Typically, a six-step process is used in developing the electric deliveries forecast. The first step in the process is gathering the class-level historical monthly electric delivery, monthly customer counts, monthly number of billing days, monthly binaries to account for seasonal variation, and daily temperature information. Most observations are entered directly int the modeling framework as dependent and explanatory variables. The daily temperature information, however, is transformed to monthly heating degree days ("HDD") and cooling degree days ("CDD") variables prior to entering the modeling framework. The second step is importing the economic and demographic variables from S&P Global (formerly, IHS Markit) into the sales modeling framework. These variables cover historical data going back to 2001, the start of the time horizon within the regression modeling process, as well as projections to the test year. The third step is importing electric use forecasts for wholesale, electric vehicles, polycrystalline production, Distributed Generation ("DG"), and energy savings from the Company's EWR programs. These forecasts are exogenous to the modeling framework and were either adopted by the Commission in prior electric rate cases, reflect current industry expectations, or are based on end-use analyses. The fourth step is reviewing the imported observations to identify data issues before running the econometric models. In situations when erroneous data is observed, it is either corrected where possible or removed from the models. The fifth step is executing the regression functions and reviewing the corresponding statistical metrics. The final step in the sales forecasting process is to combine the regression forecasts with the external forecasts imported in step three.[2478]

[2478] 3 Tr 937-938.

He stated that the peak demand forecast process is like that of the electric delivery forecast.

> The first step in the peak demand forecast is importing the Company's monthly system peak demands, corresponding minimum and maximum daily temperature, forecasted base electric deliveries, seasonal binaries, and number of customers into the demand modeling framework. An average of the minimum and maximum temperatures is used to develop the peak CDD and HDD variables before these variables are imported into the model framework. The second step is reviewing the imported observations to identify data issues before executing the peak demand econometric model. The third step is regressing the observed peak demands against the seasonal binary, degree day, and forecasted base electric sales. The final step in the peak demand forecasting process is combining the results of the econometric model with the Company's projected peak demand adjustments, which consists of the following: (1) EWR; (2) Dynamic Peak Pricing ("DPP") programs; (3) Conservation Voltage Reduction ("CVR"); and (4) Residential Summer On-Peak rate ("RSP").[2479]

Mr. Breuring testified that the key variables affecting the electric deliveries and demand forecasts are weather, the economy, and demographics, as well as variables related to EWR, DG, Electric Vehicles (EVs), and the COVID-19 pandemic, with weather being the primary variable used in the forecasting models to capture the seasonal variation in deliveries and demand across the year.[2480]

Mr. Breuring stated that for at least the last 15 years, Consumers has utilized MetrixND for its regression modeling, adding that MetrixND is considered an industry standard.[2481] He added that Consumers uses economic indicators to capture the growth expectations related to increased economic activity in its service territory, which

[2479] 3 Tr 938-939.
[2480] 3 Tr 941.
[2481] Id.

primarily includes employment and industrial production forecasts provided by S&P Global, a publishing company that provides industry-specific data and analyses.[2482]

Mr. Breuring testified that Consumers projects jurisdictional electric deliveries of 33,918,733 MWh for the test year.[2483] He added that Consumers has provided both historical and forecasted sales on both a cycle-billed and calendar basis and 60-months of the most recent actual historical, weather-normalized historical, and projected sales, as directed by the Commission in its Order in Case No. U-21585.[2484]

Mr. Breuring stated that in the years since 2019 (pre-pandemic), weather-normalized electric deliveries have remained virtually flat at a -0.1% decrease versus 2024 (the historical year), with the industrial class changing -5.1%, and the commercial class changing 0.0%, while the residential class showed an increase of 1.0% during this period.[2485] He added that following 2019, Consumers' deliveries were impacted by the COVID-19 virus and the resulting pandemic, and that in 2020, the pandemic caused significant customer behavioral changes, such as an increase in remote working and temporary cessations or reductions in in-person operations for some C&I customers.[2486] He stated that COVID-19 and the ensuing pandemic had an inverse effect on Consumers' residential and C&I customer classes, as in 2020, the residential deliveries increased 5.2% over 2019 on a weather-adjusted basis while weather-adjusted C&I (excl. LTILRR) deliveries decreased by 6.2% and 8.0%, respectively.[2487] He added that generally, each customer class has returned to a "post-pandemic" trend such that these

---

[2482] 3 Tr 942.
[2483] 3 Tr 942; Ex. A-15, Sch. E-2.
[2484] 3 Tr 945; Part III, attachments 014, 015, 016.
[2485] 3 Tr 945.
[2486] 3 Tr 946.
[2487] Id.

classes have mostly recovered from the significant impact the pandemic had on their individual trends (residential class up, commercial flat, and industrial class down).[2488]

Mr. Breuring stated that test year deliveries are projected at 38,662 GWh, which is an approximate two-year compound annual growth rate (CAGR) of +2.5% over the weather-normalized historical year 2024 of 36,776 GWh.[2489] He added that 3.6% of this growth is attributable to LTILRR/LED, and that excluding LTILRR/LED, the two-year CAGR is -1.1%.[2490]

Mr. Breuring stated that the main driver of change in deliveries between the historical year and the test year is related to LTILRR volumes (represented in Primary Demand GPD), which are excluded in the test year, but have not been removed from the historical period.[2491] He noted that deliveries related to Grand Rapids (GR) Streetlighting are also excluded from the test year which is considered non-jurisdictional.[2492] He added that same as the last rate case, GR test year volumes and revenues are categorized as miscellaneous, with its deliveries (MWh) being excluded from the test year, while its revenues are included in miscellaneous revenues.[2493] He stated that no wholesale deliveries are shown in the test year as the single wholesale customer (non-jurisdictional) has ceased its contract with the Consumers as of the end of 2024.[2494]

[2488] Id.
[2489] 3 Tr 947; Ex. A-15, Sch.E-1.
[2490] Id.
[2491] Id.
[2492] Id.
[2493] Id.; Ex. A-15, Sch. E-2.
[2494] Id.

Mr. Breuring stated that the residential customer class is projected to grow at a 0.2% CAGR from 2019 (pre-pandemic) to the test year, noting that the residential class increased significantly in 2020 due to, among other things, many people working from home (+5.2%, year-over-year).[2495] He added that 2021 was seen as a correction with deliveries reducing by 2.7% as some workers returned to in-person work at an office location, and that as a result of this reversion to pre-pandemic behavior regarding work locations, residential deliveries are projected to continue to level out toward the test year.[2496]

Mr. Breuring stated that the commercial customer class is projected to recede by a -0.2% CAGR from 2019 (pre-pandemic) to the test year. He noted that the commercial class decreased significantly in 2020 due to the negative impact the pandemic had on retail, schools, restaurants, and other commercial customers (-6.2%, year-over-year).[2497] He added that 2021 marked an improvement for these commercial sectors, which is reflected by the 3.3% year-over-year increase in deliveries, with commercial deliveries being projected to level out toward the test year, though total deliveries in the test year are still below the pre-pandemic year of 2019 by a -0.2% CAGR.[2498] He stated that the majority of the reduction in projected deliveries in the commercial class is due to increased levels of EWR from the historical year to the test year.[2499]

[2495] 3 Tr 948, Fig. 2.
[2496] Id.
[2497] 3 Tr 948-949, Fig. 3.
[2498] Id.
[2499] 3 Tr 949.

Mr. Breuring stated that the industrial class is projected to recede by a -1.3% CAGR from pre-pandemic to the test year.[2500] He asserted that initially, in 2020, the industrial class was impacted more drastically than the other classes, as the class decreased by 8.0% year-over-year, but that two years later, in 2022, this class regained most of its lost sales since the pandemic.[2501] He added that from the historical year to the test year, EWR pressures push the deliveries down.[2502]

Mr. Breuring stated that Consumers is expecting the number of EVs in its service territory to grow from 39,950 in 2024 to an estimated 122,989 EVs by the test year, which is a 68% CAGR.[2503] He added that these 122,989 EVs will add incremental annual electric load of approximately 480 GWh.[2504] He asserted that the increased load is not due to EVs concentrated only around the residential customer class, stating that of the total anticipated incremental EV load of 480 GWh in the test year, 314 GWh (65%) is expected to be residential, with the other 166 GWh (35%) being allocated to the business sector.[2505]

Mr. Breuring stated that distributed generation, or DG, remains a relatively small piece of total deliveries in the test year, with DG being expected to increase at a faster growth rate than historical levels.[2506] He added that in 2025, DG is expected to reduce

---

[2500] Id.
[2501] 3 Tr 949-950, Fig. 4.
[2502] 3 Tr 950.
[2503] Id.
[2504] Id.
[2505] Id.
[2506] 3 Tr 951.

residential deliveries by 37 GWh, or 0.30% of total residential load, and that for the test year, DG is projected to increase to 44 GWh, or 0.35% of total residential load.[2507]

Mr. Breuring stated that since 2017, Consumers' electric deliveries forecast factored in its commitment to help customers reduce energy waste by at least 1.5% per year.[2508] He added that from 2024 to the test year, Consumers is expected to grow EWR savings to 1.9%, as filed in Consumers' latest IRP proceeding, Case No. U-21090.[2509] He stated that at the test year, Consumers'' projected EWR savings are 1.7%, with the residential class being projected at 1.1% and the business class (C&I) projected at savings of around 1.8%.[2510]

Mr. Breuring stated that weather-normal peak demand grew at 1.6% CAGR from 2003 to 2007 but reversed much of this trend during the 2007 to 2009 recession. He maintained that looking forward, peak demand is expected to increase 0.5% per year from 2024 to 2029.[2511]

He stated that the peak demand forecast is reduced by approximately 34 MW in 2025 and 40 MW in 2029 because of Dynamic Peak Pricing (DPP) programs.[2512] He asserted that additional adjustments to peak demand include EWR and CVR measures, which are estimated to reduce peak demand by 869 MW and 63 MW, respectively, in 2025, with the reductions increasing to 1004 (EWR) and 87 (CVR) in the projected test

---

[2507] Id.
[2508] Id.
[2509] Id.
[2510] 3 Tr 951-952.
[2511] 3 Tr 952; Ex. A-15, Sch. E-4.
[2512] 3 Tr 953.

year.[2513] Lastly, he stated that the Residential Summer On-Peak (RSP) rate is expected to reduce peak demand by approximately 66 MW in the test year.[2514]

Staff witness Ausum recommended increasing Consumers' commercial deliveries forecast by 204,656 MWh for customers receiving bundled service and 16,308 MWh for customers receiving retail open access (ROA), or "choice" service.[2515] He stated that the proposed increases are the result of adjustments to Consumers' regression models based on Staff's analysis of the models in their native format, which results in improved model outputs and a more accurate forecast of deliveries.[2516]

Staff did not propose any adjustments to Consumers' residential forecast, however, Mr. Ausum requested that Consumers provide additional information in its next rate case to explain: the rationale for using two different models; the reason for the calibration variable, and why the MetrixND forecasts differ so largely from what is contained in the Part III Attachment 016 of Consumers' rate case application.[2517]

Mr. Ausum explained that Consumers also uses two models to derive its commercial forecast: a "use-per-customer" (upc) model weighted at 40% and a "total commercial deliveries" model weighted at 60%.[2518] He testified that Consumers' explanation for the weights given to each of the two models was only that "the weighting scheme 'provides weight to each model to increase flexibility in modeling.'"[2519]

[2513] Id.
[2514] Id.
[2515] 6 Tr 4271; Ex. S-15.0.
[2516] 6 Tr 4272.
[2517] 6 Tr 4274-4275; Ex. S-15.3 and S-15.4.
[2518] 6 Tr 4275; Ex. S-15.2.
[2519] 6 Tr 4275; Ex. S-15.6.

He asserted that in Staff's opinion, combining the two models does not produce a more accurate forecast. He explained that an analysis of the model statistics shows that the commercial use-per-customer model is better able to explain variations in customer usage (as measured by adjusted R^2) and is less prone to error (as measured by Mean Absolute Percentage Error, or MAPE) and therefore the model has more explanatory power than the total deliveries model.[2520] He added that an out-of-sample test of accuracy also shows that the use-per-customer model fell closer to both actual and weather normal cycle billed deliveries.[2521] He questioned why Consumers used two models to forecast commercial load, when it appears that one model (use-per-customer) does a much better job.[2522]

Mr. Ausum discussed Consumers' method of forecasting commercial customer count, noting that the historical customer count input to the model only included the number of bundled commercial customers and did not include choice customers.[2523] He testified that Consumers explained that, "[d]ue to their relatively static nature, the number of choice customers the Company expects to serve in the test year was not modeled explicitly in the commercial customer regression model."[2524] He added that Consumers indicated that instead of explicitly modeling the number of choice customers for the test year, it held the number to 844, the most recent monthly customer choice count.[2525] According to Mr. Ausum, Staff does not take issue with Consumer's method to forecast customer count generally, but omitting choice customers becomes

---

[2520] 6 Tr 4275-4276; Ex. S-15.7.
[2521] 6 Tr 4276; Ex. S-15.7.
[2522] 6 Tr 4276.
[2523] 6 Tr 4277.
[2524] Id.; S-15.8.
[2525] Id.

problematic when deliveries are forecast with a use-per-customer model.[2526] He explained that "[i]f use-per-customer is calculated and then modeled in MetrixND with choice load included, but the forecast of commercial customers does not include choice customers, the resulting MWh forecast has the potential to be understated."[2527] Accordingly, he recommended an adjustment which adds the expected number of choice customers (844 per month) back into commercial customer counts before multiplying forecasted use-per-customer. He maintained that this provides a better estimate of commercial MWh load in the test year.[2528]

Next, Mr. Ausum discussed Staff's recommended commercial models, which are focused solely on use-per-customer multiplied by the number of customers.[2529] He explained Staff's recommended method and the differences with Consumers' models:

> Staff began by adding together historical bundled and choice load, as well as historical bundled and choice customer counts, which were sourced from previous Company rate case filing attachments and annual P-521 reports to the Commission. The combined load was divided by the combined customer count figures dating back to January 2014, the first period in the Company's training set. The resulting commercial kWh usage per customer became the dependent variable in Staff's forecast models. Staff's recommended model uses the same degree day, commercial use calibration, cycle billing days, and COVID-19 variables included in the Company's model, but omits unnecessary binary variables and substitutes non-manufacturing employment from the Company's list of economic indicators as an explanatory economic variable, instead of the Company's service employment variable. Both variables are measures of employment in the state and come from the same source of economic data included within the Company's MetrixND model file, but non-manufacturing employment is a slightly broader measure of economic activity that still corresponds with the Company's definition of commercial usage in its rate book. The only other key difference in Staff's recommended model is the inclusion of an intercept term within the regression equation. Unless a

[2526] 6 Tr 4277.
[2527] 6 Tr 4277-4278.
[2528] 6 Tr 4278.
[2529] Id.

> complete set of seasonal binary variables are used, the inclusion of an intercept term is an accepted practice in regression modeling.[2530]

He added that Staff's model has both a higher adjusted R^2 statistic, meaning that more of the variation in commercial use-per-customer is explained by Staff's choice of explanatory variables, and Staff's model has lower average in-sample MAPE, meaning that the fitted values in Staff's model fall closer to actuals than Consumers' modeling.[2531] He stated that based on Consumers' stated criteria, "Staff's model is the more reasonable choice for forecasting commercial deliveries in the test year."[2532] Additionally, he testified, Staff used out-of-sample testing with the period of July 2024 to March 2025 to analyze the predictive power of each model.[2533] He stated that Staff's model had a lower out-of-sample MAPE on both actual and, more importantly, weather normal data, further validating the use of Staff's model.[2534]

Mr. Ausum testified that Staff also made an adjustment in its MetrixND commercial forecast to account for an discrepancy between Consumers' MetrixND files and what was included in the Part III Attachment 016.[2535] He maintained that Consumers' explanation for the difference was, in Staff's opinion, irrelevant.[2536] As a result, to achieve a comparable test year, he maintained that Staff's only recourse was to make what it deemed a similar fixed adjustment to its MetrixND commercial deliveries forecast.[2537]

[2530] 6 Tr 4278-4279 (internal citations omitted); Ex. S-15.9 and S-15.10.
[2531] 6 Tr 4279.
[2532] Id.
[2533] 6 Tr 4279-4280; Ex, S-15.11.
[2534] 6 Tr 4280.
[2535] Id.
[2536] Id.; Ex. S-15.12.
[2537] 6 Tr 4280.

Mr. Ausum summarized Staff's recommendations: an increase to the forecast of cycle-billed commercial deliveries by 204,656 MWh for bundled customers and 16,308 MWh for choice customers; and in future rate cases, Consumers should provide more detail for the calibration variables in the residential, commercial, and industrial deliveries models and explain why the MetrixND model outputs are adjusted before they appear in the Part III Attachment 016.[2538]

In rebuttal, Mr. Breuring disagreed with Staff's proposed increase to commercial deliveries, asserting that it is not supported by historical trends, it was derived using a limited regression model, and the model used a statistically weak variable.[2539]

Mr. Breuring described historical trends in the commercial bundled class and compared them to Staff's forecast. He testified that since 2020, the commercial bundled class has been undergoing a recovery from the impacts of the COVID-19 pandemic and a return to more normalized consumption patterns. He explained that commercial electric consumption initially rebounded after the pandemic, growing by 3.1% in 2022, and then began to stabilize in 2023 with a modest increase of 0.6%, before declining slightly by 0.3% in 2024.[2540] He asserted that this normalization is primarily driven by persistent downward pressure from EWR initiatives, which reduce deliveries by approximately 1.8% annually, and while growth factors such as economic activity, increases in customer count, and EV adoption, provide some upward momentum, each of their impacts has been modest.[2541] He stated that historical delivery growth remains

[2538] 6 Tr 4281-4282.
[2539] 3 Tr 957.
[2540] Id., Fig. 1.
[2541] 3 Tr 957-958.

marginal, reflected in a CAGR of just +0.2% from 2022 to 2024.[2542] According to Mr. Breuring, incorporating Staff's proposed increase in commercial bundled deliveries results in a projected two-year CAGR of 1.0% for the test year, in comparison to Consumers' forecast which reflects a more modest two-year CAGR of 0.1%, which is in line with the two-year historical CAGR of +0.2%.[2543] Mr. Breuring contended that achieving a 1.0% annual growth rate by the test year, as Mr. Ausum suggests, represents a significant departure from recent historical delivery trends that would only be plausible under conditions of substantial expansion in EV adoption, economic activity, commercial customer counts, or a combination thereof.[2544]

Referring to EV adoption, Mr. Breuring stated that Consumers already incorporates commercial EV growth (+0.47% CAGR) in the test year and it is highly improbable that its projections are understated by as much as 24%, or an incremental 152,000 vehicles.[2545]

As for economic activity, he testified that it is unlikely that the economy in Consumers' service territory would support Staff's proposed growth in commercial deliveries. He maintained that the primary growth drivers used in Consumers' regression models are sourced from S&P Global, a reputable provider of industry-specific forecast data tailored to Consumers' service territory.[2546] He asserted that the two-year CAGR leading up to the test year is 0.1% if service employment, Consumers' chosen economic indicator, is used, while it is 0.17% if Staff's indicator, non-

[2542] 3 Tr 958.
[2543] 3 Tr 958-959, Fig. 2.
[2544] 3 Tr 959.
[2545] Id.
[2546] Id.

manufacturing employment, is used.[2547] He opined that neither of these modest growth rates support the level of commercial delivery increase proposed by Staff.[2548]

Lastly, he maintained that growth in customer counts cannot support Staff's proposed growth in commercial delivery. He stated that the two-year CAGR for bundled commercial customer count leading up to the end of the test year shows a reduction of -0.22%.[2549] He added moreover that Staff used the same customer count projections as Consumers, indicating no material difference in assumptions.[2550]

Mr. Breuring testified that it is concerning that 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.[2551] He asserted that this narrow approach overlooks the importance of integrating recent trends and forecaster experience, which are essential for producing accurate and responsive load projections.[2552] He opined that "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."[2553] He testified that a hybrid approach that merges statistical models with human expertise results in forecasts that are more reliable and more responsive to change.[2554]

Mr. Breuring testified that Consumers' commercial load forecast incorporates both regression modeling and expert judgment to align recent growth trends in EV

[2547] 3 Tr 960.
[2548] Id.
[2549] 3 Tr 960; Part III, attachments 105 and 016.
[2550] 3 Tr 960.
[2551] Id.
[2552] Id.
[2553] 3 Tr 961.
[2554] Id.

adoption, economic activity, and customer growth with model outputs.[2555] On the other hand, he asserted that Staff's forecast relies almost entirely on its regression model output and instead of developing its own manual adjustment to reflect recent trends, Staff adopted Consumers' absolute adjustment value.[2556] He maintained that Consumers used this adjustment to align the model with observed growth rates over the past 12-24 months, while Staff applied the same fixed value directly to its own model without further refinement.[2557] He stated that this results in a growth rate that lacks proper justification and projected commercial growth that appears overstated, especially when considering the downward pressure from EWR savings of 1.8%, annually.[2558]

Noting that Staff also used MetrixND software in this rate case, Mr. Breuring testified that Staff's commercial regression models closely resemble Consumers' models, except that Staff uses non-manufacturing employment as its economic indicator and introduces an extra explanatory variable, labeled "constant," in an effort to enhance the model's performance.[2559] He maintained that since regression models are inherently flexible, he doesn't entirely see an issue with Staff's approach, however, he maintained that the inclusion of a constant variable raises concerns regarding the model's statistical robustness and explanatory relevance.[2560] He explained that:

> [T]he 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

---

[2555] 3 Tr 961-962.
[2556] 3 Tr 962.
[2557] Id.
[2558] Id.
[2559] 3 Tr 962-963.
[2560] 3 Tr 963.

> explaining the dependent variable. Variables that fall outside these thresholds should be excluded due to their limited explanatory power.[2561]

He maintained that Staff's newly introduced constant, with a t-stat of 1.43 and a p-value of 15.54%, does not meet the criteria for a meaningful dependent variable, which suggests that it is statistically weak and unlikely to enhance the model's predictive accuracy.[2562] He added that while including a statistically weak variable does not inherently harm the model's performance, it does not contribute meaningful explanatory power and may simply add noise rather than insight.[2563]

As for Consumers' use of both a "use-per-customer" model and a "total delivery" model, Mr. Breuring disagreed that it delivers a less accurate forecast. Rather, he stated, "it introduces a valuable level of flexibility" and "allows for cross-validation between different forecasting perspectives."[2564] He added that using both models helps mitigate the risks associated with relying on a single method and enhances the robustness of the projections.[2565] Furthermore, he asserted, since each model yields slightly different results, applying different weightings can offer a more balanced analytical perspective.[2566] He opined that the accuracy of a forecast should be based on its statistical performance and reasonableness not solely on the number of models employed.[2567]

Consumers' brief elaborates on Mr. Breuring's testimony and argues that Staff's proposed commercial load forecast should be rejected because it is out of sync with

---

[2561] 3 Tr 964.
[2562] Id.
[2563] 3 Tr 964.
[2564] Id.
[2565] 3 Tr 964-965.
[2566] 3 Tr 965.
[2567] Id.

recent historical trends, is solely based on the regression model without using the forecaster's expert judgment, and the model uses a statistically weak (t-stat less than 2 and p-value over 0.05) constant variable.[2568] Consumers argues that its forecast is better than Staff's because of the predictive accuracy of the variables used in its model, as well as the adjustments made for historical trends.[2569]

In its brief, Staff rejoins Mr. Breuring's rebuttal that a hybrid approach combining statistical modeling with human expertise results in more reliable forecasts than regression modeling alone. Staff notes that it adjusted its regression output, incorporated the same EV load forecast as Consumers, and increased the number of customers in Consumers' customer forecast, which reduces the estimated use-per customer.[2570] Staff underscores that its adjustments are driven by "complete emphasis on a [use-per customer] model," which it believes is the more accurate and reasonable way to model commercial load.[2571] Staff argues that hybrid forecasting could be useful, if it produces accurate results, but Consumers has not demonstrated that this is true. Staff notes that it asked Consumers what post-regression, exogenous adjustments it made to arrive at its sales projections, but received no explanation as to the procedure and magnitude that would allow anything other than the application of the "same fixed value[s]" to its model outputs.[2572]

[2568] Consumers initial brief, p. 302-204.
[2569] Id., p. 304.
[2570] Staff initial brief, p. 101-102.
[2571] Id., p. 102.
[2572] Id.

In response to Mr. Breuring's criticism of Staff's constant, or intercept, term, Staff maintains that it should be included in the model if there is no reason to omit it.[2573] Staff adds that if Consumers' criteria for variable selection were applied to its commercial customer count model, it would lead to the removal of the population variable[2574] Staff argues that statistical significance, while important, is not the primary concern of forecasting models, which is to predict future values with high accuracy.[2575] Staff asserts that an ideal model is one that is both highly accurate and uses variables that explain variation in either load or customers with a high degree of certainty (as measured by t-statistics and p-values).[2576]

As for the use of two regression models, Staff does not disagree that the weighting of two different models offers flexibility, as Consumers contends, but Staff argues that the practicality of that flexibility is unapparent when the goal of any forecast model is accuracy.[2577] Staff maintains that, "[i]f anything, a [use-per customer] model offers *more* flexibility than any combination of models, because the effects of changes in end-uses can be included in the [ ] model to estimate the effects of changes in end-use stock and intensities with much more visibility than a model that places total load as the variable it seeks to explain variations in."[2578] Staff concludes that its commercial forecasting model has better in-sample measures of model fit, and most importantly, proves more accurate than Consumers' model in the time leading up to the test year.[2579]

[2573] Id., p. 103.
[2574] Id., citing Ex. S-15.1.
[2575] Staff initial brief, p. 103.
[2576] Id.
[2577] Id., p. 103-104.
[2578] Id., p. 104.
[2579] Id.

Consumers provides no further argument on these issues in its reply brief.

In its reply, Staff asserts that its forecast only differs from Consumers' as to deliveries to commercial customers. Staff emphasizes that it used the same weather, billing cycle period, binary and COVID-19 variables as Consumers, and a slightly broader measure of commercial sector employment as an economic driver of sales.[2580] Staff argues that the Commission should not rely on historical trends to determine which model to use for setting rates, but instead should rely on proven measures of accuracy, and since Staff has demonstrated that its model can predict sales more accurately than Consumers' model, it should be the model the Commission adopts.[2581]

Staff takes issue with Consumers' assertion that Staff's model required different adjustments than the Company's, stating that if this is so, then Consumers should fully explain the post-regression adjustments (beyond EWR, EVs and distributed generation) that are necessary to create an accurate forecast."[2582] Staff argues that the only conclusion it could draw from Consumers' offered explanation was that it used an absolute value without refinement.[2583] Staff contends that its model is the most accurate before any adjustments are made and it stands to reason that it will continue to be the most accurate after any adjustments are added.[2584]

Staff addresses its use of the constant, or intercept, term and notes that it is a standard feature of any linear regression model and moreover, Consumers uses "statistically weak" variables (based on t-stat and p-value criteria) in its residential

---

[2580] Staff reply brief, p. 14.
[2581] Id., p. 15; Ex. S-15.11.
[2582] Staff reply brief, p. 16.
[2583] Id.; Ex. S-15.12.
[2584] Staff reply brief, p. 16-17.

deliveries models, commercial customer count model, and industrial deliveries model.[2585] Staff states that, [i]f the Company is going to pillory Staff over the use of an intercept term in a linear regression model because of the underlying t-statistics and p-values, it should first apply the same standard to the models it creates."[2586]

This PFD adopts Staff's proposed increase to Consumers' commercial deliveries forecast by 204,656 MWh for customers receiving bundled service and 16,308 MWh for choice customers. While this PFD finds Consumers' description of recent historical commercial trends noteworthy, it disagrees that historical trends are more important than model accuracy. Staff demonstrated that its model has more predictive accuracy than Consumers' model based on a higher R^2 and a lower MAPE and based on out-of-sample testing. This PFD finds that Consumers' did not demonstrate that the use of manual adjustments to align model output with historical trends produced more accurate or robust forecasts. Further, this PFD does not find that Staff's use of a constant, or intercept, affected the accuracy of Staff's model.

This PFD also finds that Staff's recommendations that Consumers provide certain information in future rate cases would be beneficial and assist the Commission. Accordingly, this PFD recommends that in future rate cases, Consumers provide more detail for the calibration variables in its residential, commercial, and industrial deliveries models and explain why the MetrixND model outputs are adjusted before they appear in the Company's rate case application.

[2585] Id., p. 17.
[2586] Id., p. 18.

2. Total Electric Operating Revenues

Consumers projected adjusted total operating revenues of $5.019 billion in the test year.[2587] Mr. Breuring testified that Consumers' projected base tariff revenues are offset by $18.3 million for the RSC customer credit, $6.1 million for the RIA credit, and $1.5 million for the LIA credit.[2588]

Staff recommends total operating revenues of $5,046,514,000 based on its increase to Consumers' sales forecast, which increases sales revenue and PSCR expenses.[2589]

As it has adopted Staff's recommended increases to the sales forecast and PSCR expenses, this PFD also adopts Staff's recommended total operating revenues.

B. Fuel, Purchased, and Interchange Power Expense

Ms. Jerore presented Consumers' forecasted PSCR costs, which were derived using the Aurora Production Costing Program (Aurora), the same platform used in the Company's 2021 IRP filing, Case No. U-21090.[2590] Consumers is forecasting $1.288 billion of total fuel, variable purchased, and net interchange expense, and $366.140 million of total capacity and non-utility generator fixed costs.[2591] These amounts, together with the test year transmission expense of $631.863 million, the MISO Schedule 2 (Reactive) credit of $0, and the reagent expenses for pollution control equipment and nitrogen oxide allowances that are expected to be recovered as part of the Company's PSCR proceedings, are the total power supply costs for the test year of

[2587] Ex. A-15, Sch. E-2.
[2588] 3 Tr 944; Ex. A-15, Sch. E-2.
[2589] Staff initial brief, p. 94, App. C.
[2590] 3 Tr 1775.
[2591] 3 Tr 1774-1778; Ex. A-160.

$2.289 billion.[2592] Ms. Jerore testified that Consumers expects to recover $121,588,000 of these costs under the Long-Term Industrial Load Retention Rate (LTILRR), $63,092,000 under the Large Economic Development Rate (LEDR), and $2,103,953,000 from remaining full-service customers.[2593]

Staff witness Maio recommended an increase to Consumers' proposed power supply expenses of $12,228,188 based on Staff's view that the Company's sales forecast should be increased and accordingly its power supply revenues.[2594] She explained that the increase in power supply revenues requires a corresponding increase in fuel and purchased power expenses to ensure that the revenue deficiency is not impacted, as these costs are reviewed and reconciled separately in annual PSCR filings.[2595] She noted that she calculated the recommended increase by multiplying Staff's sales adjustment by the PSCR base at sales level ($12,228,188 = 204,655.87 MWh * $59.75/MWh).[2596]

In rebuttal, Ms. Jerore disagreed with Staff's recommended power supply cost increase of $12,228,188. She asserted that while $12,228,188 is a fair approximation of the necessary increase in PSCR expenses, it is imprecise as it was derived in an overly simplified manner.[2597] She explained that the appropriate way to determine the impact of Staff's adjustment to the sales forecast is to input Staff's proposed sales forecast (an increase of 204,655 MWh) into the Aurora model, while keeping other inputs the same. She recommended that if the Commission agrees with Staff and increases the sales

---

[2592] Ex. A-160.
[2593] 3 Tr 1782; Ex. A-160.
[2594] 6 Tr 4472; Ex. A-52.
[2595] 6 Tr 4472.
[2596] Id.
[2597] 3 Tr 1800.

forecast by 204,655 MWh, the appropriate increase to power supply costs as determined by Aurora would be $11,587,168.[2598]

In its brief, Consumers reiterates Ms. Jerore's testimony, while noting that the Company's total projected power supply cost for the test year is $2.313 billion after adding in intersystem sales revenue.[2599] Consumers notes that the only dispute concerning the Company's calculation of the power supply expense is Staff's adjustment based on recommended changes to the sales forecast.[2600] Consumers' reasserts Ms. Jerore's testimony that if Staff's recommendation to the sales forecast is approved, the impact on the PSCR would only increase by $11.6 million rather than $12.2 million.[2601]

In its brief, Staff accepts $11,587,000 as the appropriate increase to power supply costs from Staff's recommended sales forecast, as determined by the Aurora model.[2602] As a result, Staff recommends total power supply costs expense of $2,324,829,000, which is $11,587,000 greater than the Company's projection of $2,313,242,000.[2603]

This PFD notes that it has adopted Staff's recommended increase to the sales forecast and therefore adopts the agreed to adjustment of $11,587,000 based on the Aurora model, which leads to a total power supply costs expense of $2,324,829,000.

[2598] Id.
[2599] Consumers initial brief, p. 306; Ex. A-52.
[2600] Consumers initial brief, p. 306.
[2601] Id., p. 307.
[2602] Staff initial brief, p. 107.
[2603] Id., p. 106, App. C.

C. Other O&M Expense

1. Distribution O&M Expense

a. Electric Operations

i. Non-Forestry Reliability

Mr. Kelly testified that Electric Operations was comprised of O&M Associated with Construction; Non-Forestry Reliability (Forestry-related Reliability was discussed in Ms. Stewart's testimony); Operations, Maintenance, and Metering; Service Restoration; Field Operations; Compliance and Controls; Planning and Scheduling; Work Management and Customer Delivery; Operations Management; and Operations IT Projects.[2604]

The Company's Non-Forestry Reliability O&M Program focused on inspecting and monitoring system equipment. The Non-Forestry Reliability Program consisted of four sub-programs: LVD Lines Reliability; HVD Lines Reliability; LVD Substations Reliability; and HVD Substations Reliability.[2605] Mr. Kelly explained that the LVD Lines Reliability O&M sub-program supplemented the LVD Lines Reliability capital sub-program through inspection and maintenance of LVD lines and LVD Metro assets; including general pole and line inspections, padmount inspections, and inspections of devices and equipment like reclosers, switches, and capacitors.[2606]

LVD Lines Reliability

General LVD line inspections are conducted and issues identified in those inspections that would not be capital replacements would be corrected through this

[2604] 3 Tr 1497-98.
[2605] 3 Tr 1498.
[2606] 3 Tr 1498-99.

O&M program; issues that do require capital replacements would generally be addressed in the LVD Lines Demand Failures sub-program.[2607] This also included groundline pole inspections to identify individual LVD poles that need to be replaced. Groundline pole inspections are discussed in more detail in Ms. Partlan's testimony.[2608] Mr. Kelly testified that the exterior of padmounted equipment (including the base) was visually inspected each year for any signs of leaking oil, holes that expose electrical components, missing transformer locks, or missing labels. If found, the holes were patched, and labels were replaced. If equipment was unrepairable, replacement of equipment was done under the LVD Lines Demand Failures sub-program as described in the testimony of Ms. Partlan.[2609] Mr. Kelly testified that the Company could remotely monitor equipment equipped with a modem to identify when it was not functioning properly. When this occurred, the device or equipment was investigated to determine the cause. If the equipment or device was unrepairable, replacement of equipment occurred under the LVD Lines Demand Failures capital sub-program.[2610] However, he noted that equipment without a modem needed to be inspected on a cycle to ensure proper functioning.

Mr. Kelly asserted that the work benefits customers by reducing outages caused by failed equipment, improving public safety, improving power quality, getting the full life out of installed equipment, and reducing electric load.[2611] The Company was projecting to spend $8,000,000 in the test year based on the Company's costs to complete the

[2607] 3 Tr 1499.
[2608] 3 Tr 1499.
[2609] 3 Tr 1500.
[2610] 3 Tr 1500.
[2611] 3 Tr 1501.

inspection and maintenance work.[2612] He testified that the Company was projecting to spend $3,500,000 in the test year on maintaining disconnect switches, $2,200,000 on the groundline pole inspection program, and $500,000 on padmount inspections. The remaining $1,800,000 would be spent on the other LVD inspections defined in the Reliability Roadmap.[2613] Mr. Kelly explained the increase in spending for this sub-program by noting that historic spending levels in the sub-program were insufficient to complete all the IEEE-recommended work.[2614]

Staff reviewed the Company's Electric Distribution O&M year-to-date spending through June 2025 and interpreted that to represent the amount that the Company was likely to spend going forward. In each case, Staff assumed a linear monthly spending to project likely test year spending; however, the Company asserted 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.[2615]

For the Low Voltage Distribution ("LVD") Lines Reliability O&M sub-program, Staff noted 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. The Company disagreed with Staff's recommended disallowance of $7.222 million noting that 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

[2612] 3 Tr 1502; Exhibit A-124.
[2613] 3 Tr 1502.
[2614] 3 Tr 1503.
[2615] 3 Tr 1580.

associated with the storm even for recovery in a future case. Mr. Kelly asserted that LVD Lines Reliability O&M had increased and the Company was fully planning to spend the projected amounts in the test year.[2616]

The Attorney General noted that LVD Lines Reliability O&M expense increased from $0.6 million in 2024 to $8.0 million in the projected test year. Mr. Coppola testified that the dramatic escalation in O&M expense for LVD Lines Reliability was excessive and should be moderated.[2617] In response to discovery in the last rate case (U-21585), the Company stated that it had not been following IEEE recommendations and best practices for inspection and maintenance; however, the Attorney General asserted it was not reasonable for the Company to undertake an 8-fold escalation in expense in less than two years to reverse past poor practices.[2618] The Attorney General asked the Company to provide the actual expense during the first eight months of 2025. The Company's responded showing that $607,360 was spent in the first eight months of 2025, or an annualized level of $911,000. Adding inflation adjustments to this amount would bring the expense for the projected test year to $940,000, which was less than one-eighth the Company's forecasted amount of $8.0 million for the projected test year. Therefore, the AG recommended that the Commission remove $7,060,000 from the O&M expense forecasted for the projected test year.[2619]

In response to Mr. Coppola's recommended test year disallowance of $7.060 million for the LVD Lines Reliability O&M sub-program, Mr. Kelly again referred the

---

[2616] 3 Tr 1580-81.
[2617] 3 Tr 2578; Exhibit A-124.
[2618] 3 Tr 2578.
[2619] 3 Tr 2579.

reader to his rebuttal to Staff's recommendation.[2620] In response to Staff's recommendation, Mr. Kelly noted that spending in this sub-program was not linear during the year. In a typical year, spending in this sub-program was lower in the winter and spring but ramped up in the summer and fall. 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 was on track to spend significantly closer to its projected amount. Accordingly, Mr. Kelly asserted that the projected test year was a reasonable projection of the Company's expected spending.[2621]

In its brief, the Company addressed projected expenses that are contested by the parties and argued that projected expenses, unless otherwise agreed, are reasonable should be approved by the Commission.[2622] The Company then addressed Staff's recommendation to set the projected expense based solely on actual expense in the first six months of 2025 and Attorney General witness Coppola's recommendations based on a similar argument.[2623] The Company argues the Commission should reject this methodology for projecting test year O&M expense because many programs do not follow a linear monthly spend and because it ignores the Company's evidence in support of its future O&M projections.[2624]

[2620] 3 Tr 1592-93.
[2621] 3 Tr 1582.
[2622] Company brief, pp. 307-8.
[2623] Company brief, p. 208.
[2624] Company brief, p. 208.

In its brief, Staff recommends reducing LVD Lines reliability O&M by $7,222,000.[2625] The recommendation is based on the Company provided year-to-date spend being only a fraction of the projected spend for 2025.[2626]

The Company asserts that it is not reasonable to slash the Company's projected LVD Lines Reliability O&M spending by 90% based solely on the spending in the first six months of 2025 because the Company was required to constrain 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. LVD Lines Reliability O&M was constrained in the first half of 2025 but has since increased, adopting Staff's or the Attorney General's proposed drastic reduction in this reliability funding will result in the Company unable to achieve the benefits planned for customers.[2627]

Based on dollars already spent, this PFD finds it unlikely that the Company will spend an additional $7,000,000 on the Lines Reliability LVD sub-program in 2025. Staff recommended adjusting the projected expenses for the Lines Reliability LVD sub-program based on a linear monthly spending plan and the actual expenses for the first six months of 2025, which came to $754,000. Applying a 2.40% inflation factor for 2026 and 2027, Staff projected an expenditure of $778,000 for the 12 months ending April 30, 2027, and recommended a disallowance of $7,222,000.[2628] The Attorney General also recommended an adjustment, asking the Company to provide the actual expense during the first eight months of 2025, $607,360, annualized to $911,000. Adding inflation adjustments to this amount brought the expense for the projected test year to

[2625] Staff brief, p. 109.
[2626] Staff brief, p. 110.
[2627] Company brief, pp. 108-9.
[2628] 6 Tr 4427; Exhibit S-16.2.

$940,000 resulting in the Attorney General's recommendation to remove $7,060,000 from the O&M expense for the projected test year. Considering that the five-year average for Lines Reliability LVD O&M is $574,000,[2629] just seven percent of the projected test year expense of $8,000,000, this PFD finds that it is not reasonable that the Company would spend an additional $7 million dollars in the remainder of 2025. Therefore, this PFD recommends the Commission approve $2.262 million for 2025 and $2.316 million for 2026 and 2027 (2.4% inflation factor applied) for a disallowance of $5.684 million.

HVD Lines Reliability

Mr. Kelly next addressed the HVD Lines Reliability O&M sub-program, which included the expense portion of the Company's HVD pole inspections, which occurred on a 12-year cycle; and annual Motor Operated Air Break Switches ("MOABS") tests.[2630] The inspection data and information gathered through this O&M sub-program was key information used to assist in identifying line capital projects.[2631] Additionally, these repairs and replacements significantly reduced the number of outages that would occur if this work were not performed (in the case of pole replacements) or greatly reduced the impact of outages when they did occur (in the case of MOABS).[2632]

According to Mr. Kelly, the Company was projecting to spend $891,000 in the test year based on the projected amount of work expected in this sub-program, specifically HVD pole inspections, testing of MOABS, and MOABS battery

[2629] Exhibit A-124.
[2630] 3 Tr 1503.
[2631] 3 Tr 1503.
[2632] 3 Tr 1503.

replacements.[2633] The increase in spending was being driven by increased inspections and testing to support projected investment increases in the HVD Lines Reliability capital program.[2634]

For the HVD Lines Reliability O&M sub-program, Staff noted 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. Staff proposed 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.[2635] Mr. Kelly testified that the Company's filed test year position for HVD Lines Reliability O&M was too high. However, the Company's five-year history in this sub-program shows that the Company has consistently spent at higher levels than Staff was recommended here. The Company's test year spending level should be set at the five-year average of $214,000.[2636]

The Attorney General then noted that HVD Lines Reliability O&M expense increased from $109,000 in 2024 to $891,000 in the projected test year. When asked in discovery about the increase in O&M expense for HVD Lines Reliability, the Company stated that they re-evaluated their position and that the five-year average expense amount of $214,000 was an adequate spending level. This amount is $677,000 below the $891,000 forecasted by the Company. Therefore, the Attorney General recommended the Commission remove that amount from the Company's forecasted O&M expense for the projected test year.[2637] The Company agreed with Mr. Coppola

---

[2633] 3 Tr 1504.
[2634] 3 Tr 1504.
[2635] 3 Tr 1581.
[2636] 3 Tr 1581.
[2637] 3 Tr 2579-80.

that its projected test year spending level for the HVD Lines Reliability O&M sub-program should be reset to the five-year historic average, which would be a disallowance of $677,000 from the Company's filed position.[2638]

Staff and the Attorney General recommended disallowances from the Lines Reliability HVD sub-program, and after reviewing their positions the Company stated that it had re-evaluated its position and that the five-year average expense amount of $214,000 was an adequate spending level.[2639]

In its brief, the Company agrees that its test year funding should be reduced and agrees with Mr. Coppola that the projected expense should be the five-year average amount of $214,000.[2640]

In its brief, Staff recommends reducing HVD lines reliability O&M expense by $821,000. In rebuttal, Consumers reduced HVD lines reliability O&M expense by $677,000. Staff rejects this smaller concession and continues to support its full adjustment.[2641]

Recognizing Staff's argument for a full adjustment, the Company has a valid point that all spending is not linear, whereas a five-year average may more accurately reflect the likely spend in a category. Therefore, this PFD concurs with the Attorney General and recommends the Commission disallow $677,000 from the Lines Reliability HVD sub-program.

[2638] 3 Tr 1593.
[2639] 3 Tr 1593.
[2640] Company brief, p. 309.
[2641] Staff brief, p. 110.

LVD Substations Reliability and HVD Substations Reliability

Mr. Kelly then addressed the LVD and HVD Substation Reliability sub-programs which provided proactive inspections and maintenance to equipment to maintain operational functionality of LVD and HVD substation assets, as well as the Company's Metro assets. Reactive work to fix assets already broken would be performed by this same workforce in the LVD and HVD Substations Demand O&M sub-programs.[2642] There are four separate line items for LVD and HVD substations with a single substation operations workforce performing work in four different O&M sub-programs.[2643] The Company was increasing its total substation O&M spending across the four sub-programs to better align with the Electric Substation Reliability Guidelines ("ESR-1") because historical levels of funding have not been adequate to complete sufficient inspections or to address maintenance backlogs.[2644] Inspections were particularly important because they allow the Company to monitor the health of transformers, load tap changers, oil circuit breakers, and other critical substation equipment.[2645]

Mr. Kelly testified that the LVD Substations Reliability O&M sub-program supported substation and substation equipment inspections, recloser and circuit breaker test operating, substation battery maintenance, and Metro system inspections. It also included required environmental inspections under the Spill Prevention Control and Countermeasure ("SPCC") Program and funding for 80% of the total HVD and LVD substation mowing and weed spraying expenses.[2646] Issues identified by inspections or

[2642] 3 Tr 1504.
[2643] 3 Tr 1504-5.
[2644] 3 Tr 1505.
[2645] 3 Tr 1505.
[2646] 3 Tr 1505-6.

patrols under this program were corrected through work orders in the LVD Substations Demand O&M sub-program, the LVD Substation Reliability capital sub-program, or the LVD Substation Demand Failures capital sub-program.[2647]

The LVD Substations Reliability sub-program included inspections and maintenance that help avoid LVD substation outages and includes bi-monthly patrol inspections of LVD substations to identify issues that cannot be found through other means.[2648] Maintaining equipment allows the system to be operated as intended at its most efficient level, and reduced the need for capital costs to rehabilitate or replace substations as well as decreased the frequency and duration of outages.[2649] The Company projected LVD Substations Reliability O&M expenses of $5,475,000 in the test year.[2650]

The O&M expenses for the HVD Substations Reliability sub-program included monthly substation and substation equipment inspections, breaker test operating, substation battery maintenance, required environmental inspections due to the SPCC Program, and funding for 20% of the total HVD and LVD substation mowing and weed spraying expenses.[2651] Mr. Kelly testified that the Company projected HVD Substations Reliability O&M expenses of $2,349,000 in the test year.[2652] He noted that as with LVD Substations Reliability O&M, historical funding levels in this sub-program had not been sufficient to complete substation inspections and maintenance on the appropriate

[2647] 3 Tr 1506.
[2648] 3 Tr 1506; Exhibit A-125.
[2649] 3 Tr 1507.
[2650] 3 Tr 1507; Exhibit A-125.
[2651] 3 Tr 1508; Exhibit A-125.
[2652] 3 Tr 1508; Exhibit A-125.

schedule as given in the ESR-1 guidelines, compelling the Company to defer needed work.[2653]

The Company's projected expenses for the Substations Reliability LVD sub-program were: 2025 - $784,000; 12 months ending 4/30/2027 - $891,000. The Company also spent $1,906,000 in the first 6 months of 2025.[2654] Staff agreed that the Substations Reliability LVD sub-program reduces outages by proactively inspecting the equipment to find potential failures before they occur. However, given that the Company had only spent a fraction of what was needed to meet the projected spend in 2025, Staff recommended adjusting the projected expenses.[2655] Assuming linear monthly spend, the actual expenses for the first six months of 2025 were projected to get to a total spend for 2025 of $3,821,000 ($1,906,000*2). Applying a 2.40% inflation factor for 2026 and 2027, Staff projected an expense of $3,935,000 (($3,821,000*1.024*0.667)+($3,821,000*1.024*1.024*0.333)) for the 12 months ending 4/30/2027 and recommended a disallowance of $1,540,000 ($5,475,000-$3,935,000).[2656]

The Company disagreed with Staff's recommendation, noting that spending in this sub-program was not linear during the year. In a typical year, spending in this sub-program was lower in the winter and spring but ramped up in the summer and fall. 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 was on track to spend significantly closer to its

[2653] 3 Tr 1508-9.
[2654] 6 Tr 4428; Exhibit S-16.2, Exhibit A-124.
[2655] 6 Tr 4428.
[2656] 6 Tr 4429.

projected amount. Accordingly, Mr. Kelly asserted that the projected test year was a reasonable projection of the Company's expected spending.[2657]

Ms. York testified on behalf of ABATE and expressed concerns regarding Consumers' projected test year O&M expense for LVD Lines Reliability, HVD Lines Reliability, and LVD Substations Reliability.[2658] Consumers' projected O&M expense for these subprograms drastically exceeded the historical five-year average and historical actuals for 2024. Further, she asserted that these increases were in large part due to "Other Adjustments" which accounted for $10.003 million or 99% of the increase from 2024 to the future test year. Her stated concern was that the "Other Adjustments" had not been adequately supported.[2659] Ms. York posited that the Company's testimony did not specifically describe or show the basis for how it derived these amounts, rather Mr. Kelly's direct testimony made relatively vague statements about how the projected test year amounts were determined.[2660] Further, in response to discovery, the Company admitted that the "Other Adjustments" column simply reflected the difference between Consumers' historical actual spend and its projected test year spend.[2661] Based on this information, Ms. York recommended reducing the projected O&M expense by $10.003 million, which was the amount of "Other Adjustments" included in the projections.[2662]

Ms. York next addressed O&M and Metering without Service Restoration, which included projected expenses for a subset of these subprograms including HVD Lines Demand, LVD Substation Demand, HVD Substations Demand, Staking, and Meter

---

[2657] 3 Tr 1582.
[2658] 6 Tr 3678.
[2659] 6 Tr 3680.
[2660] 6 Tr 3680.
[2661] 6 Tr 3680-81.
[2662] 6 Tr 3681.

Services.[2663] Ms. York asserted that Consumers' projected O&M expense for these subprograms drastically exceeded the historical five-year average and historical actuals for 2024. In addition, the Company's testimony and workpapers did not clearly support such significant increases in O&M spending relative to the historical amounts.[2664] She noted that in some cases, the Company's testimony provided a high-level description of its approach to developing its projected O&M spending. In other cases, rather than describing the basis for its projection, the Company focused on why the projected spending level was higher than historical amounts.[2665] Ms. York further expressed that while spending projections were shown, the supporting data did not explicitly show how the Company arrived at its test year projections.[2666] As a result, Ms. York recommended reducing the projected O&M expense for these subprograms by $18.118 million. This was equivalent to the removing the "Other Adjustments" for these subprograms and would bring the projected spend more in line with the five-year average.[2667]

The Company noted that Ms. York focused on "Other Adjustments", with multiple disallowances based on the idea that these adjustments were not properly supported.[2668] Mr. Kelly asserted that the Company did not develop projected distribution O&M spending by starting with the most recent historical year, adding inflation, and then making adjustments from that level; rather, projected distribution O&M spending was usually based on a projected level of work, and the specific

[2663] 6 Tr 3681.
[2664] 6 Tr 3682.
[2665] 6 Tr 3682.
[2666] 6 Tr 3683-84.
[2667] 6 Tr 3684.
[2668] 3 Tr 1602; Exhibit A-128.

approach for each O&M sub-program.[2669] The purpose of presenting the Company's distribution O&M was to illustrate what amount of the Company's projected O&M spending was tied to inflation, particularly so that interested intervenors could see the impact of different inflation rates and concluded that Ms. York's interpretation was problematic.[2670]

Ms. York stated that the "Other Adjustments" for LVD Lines Reliability O&M, HVD Lines Reliability O&M, and LVD Substations Reliability O&M are not supported and recommended that the $10,003,000 in "Other Adjustments" for these sub-programs be disallowed due to lack of detail on how these sub-programs were projected.[2671] The Company countered in rebuttal that the Company supported the total sub-program expenditures, and not just the "Other Adjustments" and provided detailed unitized information for these and other O&M sub-programs, illustrating the projected increasing workload that supports the projected increase in spending.[2672]

Ms. York also testified that the Company had 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, stating that Mr. Kelly did not provide detail about historical or projected work orders for some of these sub-programs. Ultimately Ms. York recommended that the Commission disallow the $18,118,000 in "Other Adjustments" for these 20 sub-programs.[2673] Mr. Kelly reiterated that his testimony supported the reasonableness of the Company's projections for HVD Lines

---

[2669] 3 Tr 1602; Exhibit A-128.
[2670] 3 Tr 1602; Exhibit A-128.
[2671] 3 Tr 1602-3; Exhibit A-128.
[2672] 3 Tr 1603; Exhibit A-222.
[2673] 3 Tr 1603; Exhibit A-128.

Demand O&M and Staking O&M and the appropriateness of the Company's 7% growth rate for Staking O&M.[2674]

In its brief, the Company addressed Staff's recommended reduction based on spending in the first six months of 2025 and proposed reduction in O&M expense from the projected $5.475 million test year amount to $3.935 million. The Company argues the Commission should reject this recommended reduction because the LVD Substations Reliability O&M spending is not linear during the year. Spending in this sub-program is typically lower in the winter and spring but ramps up in the summer and fall. Company spending in the third quarter of this year was nearly as much as the spending in the first half of the year, and the Company is on track to spend $4.65 million in 2025.[2675] The Company states that historical funding in this sub-program has not been sufficient to complete inspections on the schedule giving in the ESR-1 guidelines, and the increased O&M funding is to clear maintenance backlogs and get the Company on the appropriate inspection schedules.[2676]

The Company also argued that the Commission should reject ABATE's recommended reductions to LVD Lines Reliability, HVD Lines Reliability, and LVD Substations Reliability because it misunderstands the purpose of the "Other Adjustments" column in Exhibit A-128.[2677] The Company concludes on this topic that the LVD Lines Reliability, HVD Lines Reliability, and LVD Substations Reliability projected expenses are reasonable and should be approved by the Commission.[2678]

[2674] 3 Tr 1603-4; Exhibit A-128.
[2675] Company brief, p. 310; Exhibit A-219.
[2676] Company brief, p. 310.
[2677] Company brief, p. 310; Exhibit A-128.
[2678] Company brief, p. 311.

In its brief, Staff recommends reducing LVD substation reliability O&M expense by $1,540,000 based on the Company provided year to date spend in that sub-program being only a fraction of the projected spend for 2025.[2679] Staff reiterated Company and intervenor testimony on the topic and relied on Staff witness Durfee's testimony to argue that the Commission should approve Staff's disallowances because the year-to-date spend in 2025 does not support it.[2680]

In its brief, ABATE argues that the Non-Forestry Reliability expense category includes O&M expenses for, among other items, LVD Lines Reliability, HVD Lines Reliability, and LVD Substations Reliability are inadequately supported and drastically above historic actual amounts. Therefore, the Commission should reject the Company's proposal.[2681] In support, ABATE asserts that the Company did not demonstrate that cost recovery based on these "Other Adjustments" was reasonable or prudent because the Company's testimony did not specifically describe or show the basis for how it derived these amounts, instead only making vague statements about how the projected test year amounts were determined.[2682] The discovery materials referenced by the Company include general assertions regarding increased work or needs, but do not provide the granular, project-level, or workforce-specific evidence required to demonstrate prudency and necessity, particularly where these adjustments contribute substantial incremental costs to base/historical budgets.[2683] Without detailed cost breakdowns—such as itemized changes in activities, mandates, or program needs

[2679] Staff brief, p. 110.
[2680] Staff brief, pp. 110-15.
[2681] ABATE brief, p. 60.
[2682] ABATE brief, pp. 60-61.
[2683] ABATE brief, pp. 61-62.

corresponding to each Other Adjustment—the Commission is left without a clear benchmark to test these costs against historical performance or regulatory standards. Rates must be set on prudent, substantiated forecasts—not on unexplained or vaguely justified adjustments. The Company's approach would result in unjust and unreasonable rates based on claimed cost components that cannot be reviewed with sufficient scrutiny.[2684] ABATE concludes, arguing that the Company has failed to demonstrate cost recovery for these amounts is reasonable and prudent. As such the Commission should reduce the Company's projected O&M expense by $10.003 million, which is the amount of "Other Adjustments" included in the projections.[2685]

Reviewing the numbers provided by the Staff and the Company, the Company has not provided information to support the Company's assertion that it would spend as much in the third quarter as it spent in the first two quarters combined. In its brief, the Company asserts it is on track to spend $4.65 million in 2025.[2686] The Company also noted that funding has historically been insufficient to complete inspections. Noting the Company's argument that it is on track to spend $4.65 million in 2025, Staff also has a solid argument supporting its recommended disallowance. Having considered both this PFD notes that "spending is not linear" cannot work for every issue in the absence of demonstrated plans to spend; therefore, this PFD recommends the Commission disallow $1,540,000 from the Substations Reliability LVD sub-program.

Operations, Maintenance, and Metering Program (w/out Service Restoration) O&M expense program contains the following sub-programs: HVD Lines Demand; LVD

[2684] ABATE brief, p. 62.
[2685] ABATE brief, p. 63.
[2686] Company brief, p. 310.

Substations Demand; HVD Substations Demand; Corrective Maintenance; Staking; Meter Services; Meter Credits; Streetlighting; Service Calls; Alma Equipment Repair; Meter Reading; Meter Tech & Management System Support; and Smart Energy Meter Technology Center ("MTC")-Electric.[2687]

HVD Lines Demand

According to Mr. Kelly, the Company's HVD Lines Demand O&M sub-program includes certain expenses for repairs to 46 kV and 138 kV lines equipment, which address non-capital HVD failures identified in routine inspections or emergent customer-impacting events.[2688] This sub-program also includes associated on-call costs for line crews, of which there are five or six crews on call at any given time to ensure quick deployment following outages. Mr. Kelly stated that activities in this program were typically emergent and identified by failures resulting in customer outages, failures resulting in equipment outages, key calls, helicopter patrols, ground patrols, and investigation of trip and reclose occurrences.[2689] This sub-program supported preventative maintenance with repairs and upgrades of non-capital assets, downed wires, as well as splice and connector replacements.[2690] The Company was projected to spend $2,979,000 in the test year.[2691] Mr. Kelly stated that the Company was making increased use of technology, particularly infrared cameras, to identify anomalies on the HVD system, meaning more anomalies were being found and creating a backlog.[2692]

[2687] 3 Tr 1510-11; Exhibit A-125.
[2688] 3 Tr 1511.
[2689] 3 Tr 1511.
[2690] 3 Tr 1511.
[2691] 3 Tr 1512; Exhibit A-124.
[2692] 3 Tr 1512.

Staff witness Durfee provided Staff recommendations regarding the Company's projected expenses for the Lines Demand HVD sub-program were: 2025 - $2,237,000 12 months ending 4/30/2027 - $2,979,000. The Company also spent $256,000 in the first 6 months of 2025.[2693] Staff agreed that the Lines Demand HVD sub-program reduces outages and improves system integrity and reliability with preventative maintenance through repairs and upgrades of non-capital assets, downed wires, splice and connector replacements. However, given that the Company had only spent a fraction of what was needed to meet the projected spend in 2025, Staff recommended adjusting the projected expenses. Assuming linear monthly spend, the actual expenses for the first six months of 2025 were projected to get to a total spend for 2025 of $512,000 ($256,000*2). Applying a 2.40% inflation factor for 2026 and 2027, Staff projected an expense of $528,000 (($512,000*1.024*0.667)+($512,000*1.024*1.024*0.333)) for the 12 months ending 4/30/2027 and recommended a disallowance of $2,451,000 ($2,979,000-$528,000).[2694]

The Company disagreed with Staff's recommendation and objected to the Staff interpretation as an accurate representation of the amount that the Company was likely to spending going forward. In each case, Mr. Kelly stated it would be incorrect to base all projections only on a single six-month period.[2695] The Company asserted the workforce that completes HVD Lines Demand O&M work was 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 projected a modest

---

[2693] 6 Tr 4429; Exhibit S-16.2; Exhibit A-124.
[2694] 6 Tr 4430.
[2695] 3 Tr 1580.

increase in HVD Lines Reliability capital work. This would allow for more balance in the overall workplan for this workforce, which would enable the Company to complete more HVD Lines Demand O&M work in 2026 and 2027. The Company had already identified enough O&M work to account for the full test year projection.[2696]

Mr. Coppola also commented on the O&M expense for HVD Lines Demand, noting it increased from $898,000 in 2024 to $2,979,000 in the projected test year, when from 2020 to 2024, this expense never exceeded $1.1 million annually.[2697] In discovery, the Attorney General asked the Company to provide the actual year to date O&M expense for 2025. The Company responded that O&M expense for the first eight months of 2025 were only $453,130, which reflected an annualized expense level of $680,000, significantly below the Company's 2025 projection of $2.2 million.[2698] Mr. Coppola then asserted that it was apparent from this recent actual level of spending that the forecasted expense amount for the projected test year was overstated. Therefore, the Attorney General recommended that the projected test year spending level be set at $1,086,000, which was the highest expense incurred in the past five years. This amount is $1,893,000 lower than the $2,979,000 forecasted by the Company. The Attorney General recommended the Commission remove the $1,893,000 expense difference from the Company's projected test year O&M expense.[2699]

In response to Mr. Coppola's recommendation that the test year spending level should be set at the highest actual level incurred by the Company in the last five years for the HVD Lines Demand O&M sub-program, the Company disagreed. In the test year

---

[2696] 3 Tr 1583.
[2697] 3 Tr 2575; Exhibit A-124.
[2698] 3 Tr 2576.
[2699] 3 Tr 2576.

for the instant case, the Company projected a modest increase in HVD Lines Reliability capital work. This would allow for more balance in the overall workplan for this workforce, which would enable the Company to complete more HVD Lines Demand O&M work in 2026 and 2027. The Company again asserted it had already identified enough O&M work to account for the full test year projection.[2700]

In its brief, the Company argued that the Commission should reject the HVD Lines Demand O&M recommended disallowances of Staff and the Attorney General because the recommended reductions do not reflect the work that the Company will perform in the projected test year. The increased projected expenses in the HVD Lines Demand O&M sub-program will address a backlog of repairs and continue fixing anomalies as they are found.[2701] The Company asserts it has identified sufficient O&M work to be funded by the test year projection and argues that the Commission should approve its projected HVD Line Demand expense that will fund the Company's ability to make these needed system repairs.[2702]

In its brief, Staff recommends reducing the HVD lines demand O&M expense by $2,451,000 based on the Company provided year to date spend in those sub-programs being only a fraction of the projected spend for 2025.[2703]

In her brief, the Attorney General reiterated Mr. Coppola's testimony arguing that the Company did not make any claims regarding the need for additional preventive maintenance in its last rate case and year-to-date spending is significantly below the Company's 2025 projection of $2.2 million. The Attorney General then argued that since

---

[2700] 3 Tr 1583.
[2701] Company brief, p. 315.
[2702] Company brief, p. 315.
[2703] Staff brief, p. 110.

the Company failed to support its test year projection, she recommends that the Commission remove $1.89 million from the Company's forecasted O&M expense.[2704]

In its brief, ABATE argues that given the drastic unsupported difference between the Company's actual historic and projected costs the Commission should reject the Company's requested cost recovery.[2705] Neither the Company's testimony nor its workpapers supported such significant increases in O&M spending relative to the historical amounts.[2706] Rather than adequately justify these significant increases, the Company instead simply provided a high-level description of its approach.[2707] The Company's projections are based on what it projects which does not satisfy the Company's burden to provide "detailed supporting explanations and underlying assumptions rooted in expected business, financial, and economic circumstances" and instead constitutes reliance "on undocumented estimates of future ratemaking expenses and revenue criteria."[2708] The Company's actual calculations and method for projecting its costs for these subprograms is also deficient. Given its failure to adequately demonstrate its projections are reasonable or prudent, the Commission should not grant cost recovery for the same. As such the Commission should reduce the Company's projected O&M expense for these subprograms by $18.118 million. This is equivalent to removing the "Other Adjustments" for these subprograms and brings the projected spend more in line with the five-year average.[2709]

[2704] Attorney General brief, p. 174.
[2705] ABATE brief, p. 63.
[2706] ABATE brief, p. 64.
[2707] ABATE brief, p. 64.
[2708] ABATE brief, pp. 64-65.
[2709] ABATE brief, p. 67.

With actual spending in the Lines Demand HVD sub-program on track to spend less than $784,000 according to Staff and never exceeding $1.1 million annually per the Attorney General, and absent robust justification from the Company for the projected spending, this PFD concurs with the rationale of Staff and the Attorney General and recommends that the Commission disallow $2,451,000 from the HVD Lines Demand sub-program.

LVD and HVD Substations Demand

The LVD and HVD Substations Demand sub-programs respond to failures resulting in customer outages or equipment outages, poor testing results (e.g., infrared inspections, oil sampling, etc.), and substation asset management database algorithms, supporting the Company's safety and reliability objectives by ensuring customer and electric system safety, outage restoration, and repairs to equipment to maintain operational functionality of LVD and HVD substation assets.[2710] Mr. Kelly testified that the Company projected increased spending in these sub-programs to ensure the Company could complete the necessary substation maintenance under the ESR-1 guidelines, as given in the Reliability Roadmap.

The LVD Substations Demand O&M sub-program included expenses for emergent restoration and corrective maintenance on LVD substation equipment and facilities and the Company projected LVD Substations Demand O&M expenses of $6,398,000 in the projected test year.[2711] Mr. Kelly testified that the Company's HVD Substations Demand O&M sub-program included expenses for unplanned and

[2710] 3 Tr 1512.
[2711] 3 Tr 1513; Exhibit A-125.

emergent restoration, as well as corrective maintenance on HVD and Strategic Customer substation equipment and facilities, and the Company projected HVD Substations Demand O&M expenses of $5,311,000 in the projected test year.[2712] Mr. Kelly asserted that work identified through substation inspections reduced the potential for outages from unplanned events, which provided value to the customer and provided the best reliability.[2713]

In its brief, the Company noted ABATE witness York's recommended expense reductions in the amount of the "Other Adjustments" presented by Company witness Kelly.[2714] The Company argues that the Commission should approve the Company's requested funding in these sub-programs to allow for the completion of the necessary work that forms the basis of the test year projections.[2715]

In its brief, Staff recommended that the Commission reduce the Company's projected distribution capital expenditures for its demand failures – LVD substations by $1,160,000, which is a $846,000 reduction to rate base.[2716] Company witness Hayward rebuts the Staff's proposed disallowance to the LVD Substation Demand Failures sub-program, stating that the Company spent $13,357, over five years on transformers, making the average $742,061 vs $700,000. Company witness Hayward also states that transformer costs are still generally increasing, as shown by recent market data.[2717] Staff determined that the unit cost of transformers should not include an increase.[2718]

[2712] 3 Tr 1514; Exhibit A-125.
[2713] 3 Tr 1515.
[2714] Company brief, p. 317.
[2715] Company brief, p. 317.
[2716] Staff brief, p. 15.
[2717] Staff brief, p. 17.
[2718] Staff brief, p. 15.

Staff concludes by arguing that the Commission should approve Staff's disallowance to the Substation Failures-LVD sub-program because the data provided by the Company does not show a consistent increase in the Transformer unit costs over the last five years.[2719]

Having reviewed the arguments from the Company, Staff, and ABATE, this PFD notes again that "spending is not linear" cannot be the sole refrain of the Company to counter Staff's assertions that a linear reduction based on the first six months of spending. Therefore, this PFD concurs with Staff and recommends a $1,160,000 disallowance from the LVD Substation Demand Failures sub-program.

Corrective Maintenance O&M

The Corrective Maintenance O&M sub-program supported customer- and field-generated orders associated with imminent safety issues or system deficiencies, including emergent and short-term planned maintenance requirements.[2720] Mr. Kelly further asserted that this sub-program improved public safety and reliability of the system by responding to customer reported concerns, and to damage from storms and other incidents, most critically by responding to the safety issues posed by broken wires.[2721] The Company projected spending of $5,236,000 in the test year, made up largely of labor costs elevated by the annual cost-of-living adjustment and union-negotiated merit increases in pay.[2722]

This sub-program was not mentioned in briefs.

[2719] Staff brief, p. 19
[2720] 3 Tr 1516.
[2721] 3 Tr 1516.
[2722] 3 Tr 1517; Exhibit A-124.

ii. Staking & Locating

Mr. Kelly testified that O&M expenses related to the Staking & Locating sub-program involved Company labor and contractor services; work was typically performed by a contracted outside service vendor on a multi-year contract.[2723] The sub-program included the following work activity categories: Outside Services – Dedicated; Company Labor; Licenses, Permits & Fees; and System.[2724] Mr. Kelly stated that in the test year, there were no costs for Outside Services for shared contractors because the Company had transitioned to a fully dedicated staking contractor model.[2725] The dedicated contractor staking strategy was intended to improve timeliness, improved staking accuracy performance, and improved excavator communications.[2726] Based on the lower unit cost, the realized timeliness, and quality improvement from the dedicated contractor resource model, the Company elected to pursue the lower cost, dedicated contractor option and implemented a statewide dedicated contractor staking approach for its entire service territory.[2727] The Company anticipated fully pursuing a dedicated contractor model would improve timeliness by 4-5%, allowing the Company to regularly achieve 98% or greater timeliness. The Company also expected to see a 50-75% reduction in damage caused by third-party locating.[2728]

Mr. Kelly stated that the Company spent $6,148,061 on Staking & Locating in 2024, and projected $13,948,218 for the test year.[2729] He asserted that the primary

---

[2723] 3 Tr 1517.
[2724] 3 Tr 1517-18.
[2725] 3 Tr 1518.
[2726] 3 Tr 1519.
[2727] 3 Tr 1520.
[2728] 3 Tr 1520-21.
[2729] 3 Tr 1521.

drivers for increased spending in the test year in this case included: (a) increases in the cost per ticket under the contracts with staking contractors ($6,760,338 total increase) included dedicated model expansion; (b) anticipated contractor volume increases ($725,589 total increase); (c) Company labor and volume increase ($9,534 total increase); and (d) increases in MISS DIG 811 membership fees ($304,696 total increase).[2730] The Company estimated staking tickets for the test year based on the best information available; however, the largest factors influencing expenditures in these programs were externally driven. Therefore, the Company requested it be allowed to defer for refund or recovery of any O&M expenses for this program to avoid potential constraints on other important programs if higher than anticipated staking costs outside the Company's control were incurred. It would also prevent customers from paying for costs that were not incurred if staking volumes were below forecasted levels.[2731]

Staff witness Martus provided Staff's analysis and recommendations to the Commission regarding the Company's requested regulatory deferral mechanism for the Staking and Locating sub-program.[2732] Staff noted that the Company proposed an expenditure of $13,948,218 for the test year ending April 30, 2027. The Company also proposed a base unit ticket volume of 478,176 and base unit cost of $26.93/unit for the projected 2026 year and proposed a base unit ticket volume of 511,648 and base unit cost of $27.81/unit for the projected 2027 year.[2733] The Company also requested a regulatory deferral mechanism to refund spending below or recover spending above the amount in the rate case due to two projects (Realizing Opportunities with Broadband

[2730] 3 Tr 1521.
[2731] 3 Tr 1522-23.
[2732] 6 Tr 4477.
[2733] 6 Tr 4478; Exhibit S-17.

Infrastructure Networks or “ROBIN” and Broadband Equity, Access, and Deployment Program or “BEAD”) which they asserted could cause significant fluctuations in the staking volume.[2734] Staff noted that the Company made a similar request in its gas rate case U-21806 due to the Company’s concern of the “ROBIN” and “BEAD” projects introducing uncertainty in the staking ticket volume.[2735]

Staff supported the use of a regulatory deferral mechanism for the Staking and Locating sub-program. However, Staff supported the use of a regulatory deferral mechanism only for fluctuations stemming from the variability in staking volume. Therefore, Staff recommended that the recovery and refund amount for the regulatory deferral mechanism for the test year ending April 30, 2025 be set by Equation 1 below where r_amount is the recovery/refund amount, e_volume is the experienced ticket volume during the test year, p_volume is the projected ticket volume during the test year, and p_cost is the projected ticket unit cost during the test year.

Equation 1: r_amount = (e_volume – p_volume) * p_cost

Furthermore, experienced ticket volume may fluctuate by -9.13% to +3.77% from the projected amount. Staff therefore recommended for e_volume from Equation 1 to be capped to that fluctuation range. This results in Equations 2 and 3 below where c_recovery is the capped recovery amount for Equation 1 and c_refund was the capped refund amount for Equation 1.

Equation 2: c_recovery = 0.0377 * p_volume * p_cost

Equation 3: c_refund = 0.0913 * p_volume * p_cost[2736]

[2734] 6 Tr 4478.
[2735] 6 Tr 4479.
[2736] 6 Tr 4479-80; Exhibit S-17.0.

Staff asserted that its recommendation for the regulatory deferral mechanism was to use Equations 1-3 which kept p_volume and p_cost in variable form regardless of the projected staking volume and staking unit cost the Commission approved for the test year.[2737] Additionally, Staff noted that due to the similarities between the regulatory deferral mechanisms being requested in this case and case U-21806, Staff provided similar recommendations for both cases to allow for a regulatory deferral mechanism which was contingent on experienced staking volumes.

The Company did not oppose the principle that the deferral mechanism should be limited to fluctuations based on staking volume and agreed that Staff's "Equation 1" was a reasonable means of calculating what this fluctuation was in a future period. However, the Company asserted that it was not appropriate to cap the recovery or refund amounts based on historical volume fluctuations as Staff recommended.[2738] The purpose of the deferral mechanism was to address future uncertainty about staking volumes, and that uncertainty was due in large part to potential variability tied to new rural broadband programs and because future variability was tied to this new development, there should be no cap indexed to historical variability that may no longer apply.[2739] The Company was on track to have a 2025 staking volume of over 520,000, an upward variation well in excess of 3.77%, which demonstrated that Staff's proposed cap on deferral recover was out of date. As a result, the Company asserted that Staff's "Equation 2" and "Equation 3" should not be used.[2740] Should the Commission decide it wanted some kind of cap on recovery and refund in the deferral mechanism, it should at

[2737] 6 Tr 4480.
[2738] 3 Tr 1577.
[2739] 3 Tr 1577.
[2740] 3 Tr 1577-78.

least be symmetrical, such as +/- 10% in each direction. The Company stated that it would not be reasonable to create an unbalanced mechanism with nearly three times as much risk as potential benefit to the Company.[2741]

Staff witness Durfee also provided Staff recommendations regarding the Company's projected expenses for the Staking sub-program, which were: 2025 - $12,260,000 12 months ending 4/30/2027 - $13,948,000. The Company also spent $256,000 in the first 6 months of 2025.[2742] Staff agreed that the work in the Staking sub-program was necessary to keep the public and employees safe, but Staff did not agree with the anticipated volume increase of 7%. The anticipated 7% was calculated using MISS DIG 811 statewide annual growth. However, in its March 21, 2025 Order, the Commission agreed with the argument that the Company's growth rate was consistently lower than the statewide average. Therefore, Staff recommended adjusting the projected expenses. Starting with the historic staking requests received by the Company, an annual increase of 2.28% was used to project 453,113 (433,137*1.0228*1.0228) requests for 2026 and 463,444 (453,113*1.0228) requests for 2027. Using the Company's proposed unit costs for 2026 and 2027, an expense of $12,431,000 (453,113*$26.93*.667)+(463,444*$27.81*0.333) for the 12 months ending 4/30/2027 results, and Staff therefore recommended a disallowance of $1,517,000 ($13,948,000-$12,431,000).[2743]

Staff reviewed the Company's Electric Distribution O&M year-to-date spending through June 2025 and interpreted that to represent the amount that the Company was

---

[2741] 3 Tr 1578.
[2742] 6 Tr 4430; Exhibit S-16.2, Exhibit A-124.
[2743] 6 Tr 4431.

likely to spending going forward. In each case, Staff assumed a linear monthly spending to project likely test year spending. Mr. Kelly stated 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.[2744] For the Staking and Locating O&M sub-program, Staff testified that it would be inappropriate for the Company to use MISS DIG's projection of 7% statewide growth in staking volumes. Staff asserted that the Company's own recent actual staking requests supported an annual growth rate of 2.28%. Therefore, Staff recommended recalculating the Company's projected staking volumes based on this revised rate and calculated a $1.517 million disallowance based on the difference. Mr. Kelly testified that the Company anticipated greater than normal growth in staking requests due to expansion of rural broadband infrastructure which led the Company to propose a deferral mechanism for this O&M sub-program. The deferral mechanism would provide a way to refund customers if staking volumes end up lower than projected for any reason. Since Staff supported this deferral mechanism, Staff should be confident that customers would be protected if staking volumes were lower than projected. However, Mr. Kelly stated that the Company's year-to-date staking volume through September was 411,538 and the Company was on track to have a staking volume in 2025 of over 520,000, indicating robust staking growth.[2745]

Mr. Coppola also addressed the Company's Staking and Locating program, stating that there were two main issues with the Company's proposed expense for the staking and locating program in the projected test year. First, the Company had

---

[2744] 3 Tr 1580.
[2745] 3 Tr 1583-84.

overstated the number of staking and locating requests forecasted for the projected test year. Mr. Coppola noted that the 7% rate of growth asserted by Mr. Kelly was not reflective of the staking and locating requests that the Company had received annually from 2021 to 2024. Using the Company's own numbers, the actual rate of growth was 2%. At this rate of growth, the number of staking and locating requests forecasted for the projected test year are 453,640. Mr. Coppola applied the contractor's average cost rate for the year to his projected number of requests to arrive at a forecasted cost of $12,348,000. After adding the MISS Dig annual dues and fees of $734,000, the total forecasted staking and locating expense was $13,052,000. This amount is $866,000 lower than the $13,948,000 forecasted by the Company. Mr. Coppola recommended that the Commission remove the $866,000 from the Company's forecasted O&M expense for the projected test year.[2746]

Second, the Company stated that it had decided to change to a dedicated contractor approach instead of a shared contractor model throughout its service territory. The move to a dedicated contractor model increased costs dramatically from $6.1 million in 2024 to $13.9 million in the projected test year. Mr. Coppola asserted that no evidence was presented by the Company in this case that significant problems existed in the rest of the Company's service area that could not be resolved otherwise and required a costly dedicated contract approach. Therefore, Mr. Coppola considered the Company's move to an expensive dedicated model unjustified and the increase in expense imprudent. Based on the cost information provided by the Company in response to discovery, the increase in expense of expanding the dedicated model to

[2746] 3 Tr 2574; Exhibit AG-56.

other areas of the state is $5,872,000. Mr. Coppola recommended that the Commission remove the $5,872.000 from the Company's forecasted O&M expense for the projected test year.[2747] In total, for Staking and Locating, Mr. Coppola recommended that the Commission remove $6,738,000 for the projected test year O&M expense.

The Company noted that Mr. Coppola objected to the Company's use of a 7% growth rate in the Staking and Locating O&M sub-program and recommended a 2% rate be used with a corresponding disallowance of $866,000 for the lower projected volumes.[2748] In response, Mr. Kelly again asserted that 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.[2749] Mr. Coppola also objected to the Company's transition to a dedicated contractor model for staking and locating work, instead of a shared contractor model. Mr. Coppola asserted that the Company did not demonstrate that performance issues existed across the Company's service territory and recommended a substantial disallowance of $5.872 million based on the incremental cost of the dedicated model.[2750] In response, Mr. Kelly stated that 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 leaving no option for the Company to continue using a shared contractor model to save money; going forward, the dedicated contractor model was the most cost effective at $0.51 less costly on a unit cost basis than the shared contractor

[2747] 3 Tr 2574-75; Exhibit AG-56.
[2748] 3 Tr 1589; Exhibit A-12; Exhibit A-121.
[2749] 3 Tr 1589.
[2750] 3 Tr 1589-90.

option.[2751] Furthermore, the Company operated a single Staking and Locating program for both its electric and gas businesses and the Commission approved the dedicated contractor model in its most recent gas rate case, Case No. U-21806, over similar objections by Mr. Coppola.[2752]

In its brief, the Company addressed the staking regulatory deferral noting that it does not oppose the principle that the deferral mechanism should be limited to fluctuations based on staking volume and agrees that Mr. Martus's "Equation 1" is a reasonable means of calculating this fluctuation in a future period. However, the Company argues that the Commission should not cap the recovery or refund based on historical fluctuations since the purpose of the mechanism is to address staking uncertainty due to new rural broadband programs.[2753] The Company's actual staking volume for January through September 2025 is 411,518, or 22.5% higher than the staking volume in January through September 2024. This increased staking volume compared with 2024 is significantly higher than Staff's proposed 3.77% capped amount on staking volume increases. If the Commission determines that a cap is appropriate, the Company recommends a symmetrical cap of 10% for both increases and decreases in the staking volume instead of the unbalanced mechanism proposed by Staff.[2754]

The Company also argued that the Commission should reject Staff's and the Attorney General's recommended reductions because recent actual history does not reflect the expected Staking growth rate. The Company's 2025 staking volume through September is 411,538, which puts the Company on track to have a staking volume of

[2751] 3 Tr 1590-91.
[2752] 3 Tr 1590-91.
[2753] Company brief, p. 312.
[2754] Company brief, pp. 312-13.

520,000 in 2025. This is substantially above the staking volume amount that Ms. Durfee used to calculate the projected test year expense and higher than any of the annual amounts the Company originally projected through 2027 in this case.[2755] The Company also addressed Attorney General witness Coppola's disagreement with the Company's transition to a dedicated staking approach, noting that the dedicated contractor model is the most cost effective option and that the Commission agreed with the ALJ's rejection of a similar reduction recommended by the Attorney General in Case No. U-21806.[2756]

In its brief, Staff reiterates and relies on the relevant testimony covering the deferral mechanism and differences in projected volume from Staff, the Company and Attorney General witness Coppola.[2757] Noting that the Company agrees with Staff that Equation 1 is appropriate for calculating the regulatory deferral mechanism amount and no other witnesses have provided testimony regarding the regulatory deferral mechanism, Staff maintains its approval of using a regulatory deferral mechanism for the Staking and Locating program and for Equation 1 to be used to calculate the amount. However, since there is also no contention regarding the ticket unit cost in the test year, Staff is updating Equation 1 to reflect the agreed projected unit cost. The projected staking volume for the test year, p_volume, is contested between witnesses Kelly, York, Coppola, and Durfee, so it won't be assigned a value until the Commission approves an amount.[2758]

Eq. 1: r_amount = (e_volume – p_volume) * $27.22/unit.

[2755] Company brief, p. 313.
[2756] Company brief, p. 313-14.
[2757] Staff brief, pp. 179-82.
[2758] Staff brief, 182-83.

Staff is also clarifying that it supports the regulatory deferral mechanism with the intent of alleviating unpredictable staking volume fluctuations due to the new, large, and externally driven broadband programs. In addition, the mechanism is recommended because of uncertainty regarding the new broadband programs, not to address the Staking and Locating subprogram's general ticket volume fluctuations. Because of this, Staff does not support the expansion of Equation 1's caps, but Staff finds the Company's desire for a symmetrical cap reasonable. Therefore, Staff recommends for Equation 1 to be capped by the adjusted amount shown in Equation 2.

Eq. 2: cap = (+/-) 0.0377 * p_volume * $27.22/unit

Staff also recommends reducing staking O&M expense by $1,517,000 based on the Company provided year-to-date spend in those sub-programs being only a fraction of the projected spend for 2025 and because the data provided by the Company does not support a 7% increase in requests.[2759]

In her brief, the Attorney General argues that the Company's forecasted rate of growth for staking requests is too high and needs to be reduced. Based on the Company's own numbers, the actual annual rate of growth in staking and locating requests has been 2%.[2760] Mr. Coppola calculated a lower expense amount of $13,052,000 based on 453,640 projected staking and locating requests and the contractor's average cost rate plus Miss Dig annual dues and fees of $734,000. This amount is $866,000 less than the $13.9 million staking and locating expense forecasted

[2759] Staff brief, p. 110,115.
[2760] Attorney General brief, p. 169.

by the Company, which the Attorney General recommends that the Commission deduct from the Company's forecast for the projected test year.[2761]

The Attorney General also objects to the Company's decision to move to a dedicated contractor approach for its staking and locating program, which she argues increases costs dramatically from $6.1 million in 2024 to $13.9 million in the projected test year, without any evidence from the Company that a significant problem exists in the rest of the Company's service area that could not be resolved without a costly dedicated contract approach.[2762] Based on the Company's cost information, the increase in expense of expanding the dedicated model to other areas of the state is $5,872,000.567 Therefore, the Commission should remove the $5,872.000 from the Company's forecasted O&M expense for the projected test year.[2763]

The Attorney General recommends that the Commission reduce the Company's staking and locating expense by a total of $6,738,000.

In its brief, ABATE used Staking as an example to support its recommended disallowances arguing that the Company's rates should be set using a transparent, multi-year and substantiated approach for staking growth projections, rather than relying solely on projections based on temporary or speculative growth factors. Instead, the Company asserted that reliance on a 7% staking growth rate is justified due to anticipated increases from rural broadband expansion and pointed to evidence of year-to-date volumes to reinforce this position. Simply adopting MISS DIG's statewide growth estimate here fails to reflect the Company's more moderate historical growth absent

[2761] Attorney General brief, p. 169.
[2762] Attorney General brief, pp. 169-70.
[2763] Attorney General brief, p. 170.

major one-time infrastructure surges. The Company's year-over-year staking requests have previously demonstrated variability below 7%, and using a potentially atypical high point to project test-year volume risks overstating O&M needs, resulting in customer overpayment. Furthermore, if the actual growth is less than forecasted, the proposed refund mechanism will require after-the-fact correction rather than ensuring rates align with projected, most-likely outcomes.[2764]

Staff, the Attorney General, and ABATE all commented on the Company's Staking and Locating program, offering various recommendations for adjusting the projected expenses. In Case No. U-21806, the Commission approved Consumers' request for a deferred accounting mechanism based on the argument that Michigan's broadband expansion efforts, including the ROBIN and BEAD programs, may cause unanticipated fluctuation in staking volumes. The Commission adopted the ALJ's recommendation to allow the company to use a deferred accounting mechanism but agreed with Staff and found that the mechanism was only needed for fluctuations tied to ticket volume variability and is therefore subject to the conditions outlined by the Staff.[2765] Therefore, this PFD recommends the Commission approve the use of a deferred accounting mechanism, but only for fluctuations tied to ticket volume variability and subject to the conditions outlined above by Staff. This PFD also recommends the Commission (re-) approve the dedicated contractor model and disallow $1,517,000, as recommended by Staff.

[2764] ABATE brief, pp. 65-66.
[2765] September 30, 2025 order in Case No. U-21806 at pp. 211-12.

Meter Services and Credits

The Meter Services and Credits O&M sub-program funded Electric Meter Operations("EMO"), whose expenses were partially offset by first-set and retirement credits of both electric meters and metering transformers.[2766] When electric meters and metering transformers were purchased and received, the first-set credit value for each meter was totaled at the end of each month and credited back to O&M for the installation labor. When electric meters and metering transformers were retired, the cost of removal credit was totaled at the end of each month and credited back to O&M for the final removal labor. The credits were intended to partially offset the labor costs associated with new and retired metering installations.[2767] Per Mr. Kelly, the Company projected $10,257,000 in meter credits in the test year. This resulted in a net expense of $6,831,000 for the test year.[2768] Spending amounts were determined by considering projected workload and total credits were based on projections for new meter capital purchases, and projections for retirements. Because of carried over inventory, Mr. Kelly asserted that the Company had not made as many capital purchases of meters, which meant that EMO work was spread over fewer capital purchases and made Meter Services expenses higher.[2769]

In its brief, the Company addresses ABATE witness York's recommended reductions to Meter Services in the amount of "Other Adjustments" arguing that the Company did not sufficiently support its projections. The Commission should again reject Ms. York's recommended reduction of the "Other Adjustments" and approve the

[2766] 3 Tr 1526.
[2767] 3 Tr 1527.
[2768] 3 Tr 1528; Exhibit A-124.
[2769] 3 Tr 1529.

Company's requested funding in Meter Services to allow for the completion of the necessary work that forms the basis of the test year projections.[2770]

This topic is not mentioned in the Staff brief or the Attorney General's brief.

This PFD concurs with the Company and recommends that the Commission reject ABATE's proposed disallowances in this sub-program.

Alma Equipment Repair

The Company's Alma Equipment Repair O&M sub-program, based at the Company's Alma Service Center, included maintenance activities (testing, repairing, reconditioning) for assets such as mobile substation equipment, substation oil processing equipment, and substation power transformer cooling equipment.[2771] These activities were considered base level maintenance for system reliability and emergency response to demand outages. Mr. Kelly stated that the Alma Equipment Repair O&M sub-program supported safety by ensuring safe disposal of hazardous substances and offsets some costs by selling used transformer oil to parties who can use or recycle it. The Company projected spending of $571,000 in the test year.[2772] Both headcount and workload were relatively consistent in this sub-program in recent years, and test year spending was slightly higher than the five-year average to account for increased maintenance volume, with more mobile substations having been purchased by the Company.[2773]

Staff witness Durfee provided Staff recommendations on the Company's projected expenses for the Alma Equipment Repair sub-program, which were: 2025 -

[2770] Company brief, p. 317.
[2771] 3 Tr 1532.
[2772] 3 Tr 1533.
[2773] 3 Tr 1533-34.

$563,000; 12 months ending 4/30/2027 - $571,000. The Company also spent $179,000 in the first 6 months of 2025.[2774] Staff agreed that the Alma Equipment Repair sub-program reduced outages and improved system integrity and reliability with preventative maintenance through repairs and upgrades of non-capital assets, downed wires, splice and connector replacements. However, given that the Company had only spent a fraction of what was needed to meet the projected spend in 2025, Staff recommended adjusting the projected expenses. Assuming linear monthly spend, the actual expenses for the first six months of 2025 were projected to get to a total spend for 2025 of $358,000 ($179,000*2). Applying a 2.40% inflation factor for 2026 and 2027, Staff projected an expense of $370,000 ($358,000*1.024*0.667)+($358,000*1.024*1.024*0.333)) for the 12 months ending 4/30/2027 and recommended a disallowance of $201,000 ($571,000-$370,000).[2775]

The Company reiterated 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.[2776] Mr. Kelly averred it would be 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 would be a better approximation of what the Company may be capable of spending each year since it accounted for some variation that occurs on an annual basis and because it was a longer track record of data. Mr. Kelly testified that the Company's five-year average for Alma Equipment Repair O&M was $530,000, and the Company's test year projection in this case was effectively in line with that when

[2774] 6 Tr 4431; Exhibit S-16.2; Exhibit A-124.
[2775] 6 Tr 4432.
[2776] 3 Tr 1580.

accounting for inflation. Therefore, he asserted that Commission should approve the Company's projected spending level.[2777]

In its brief, the Company addresses Staff's recommended reduction based on spending in the first six months of 2025 and proposed to reduce O&M expense from the projected $571,000 test year amount to $370,000. The Company argues that projecting future spending levels based on actual spending in the first six months of 2025 fails to account for variation in spending that can occur within a year or from year-to-year. The Company notes that work in this sub-program has been relatively consistent in recent years, and the projected expense is slightly higher than the five-year average to account for increased maintenance needed for additional mobile substations, and states that the Commission should approve the Company's requested funding needed to perform the planned activities in this sub-program.[2778]

In its brief, Staff recommends reducing Alma Equipment Repair O&M expense by $201,000 based on the Company provided year to date spend in those sub-programs being only a fraction of the projected spend for 2025.[2779]

The Company projected spending of $571,000 for the Alma Equipment Repair sub-program in the test year.[2780] Both headcount and workload were relatively consistent in this sub-program in recent years, and test year spending was slightly higher than the five-year average to account for increased maintenance volume, with more mobile substations having been purchased by the Company.[2781] In fact, the

---

[2777] 3 Tr 1584.
[2778] Company brief, pp. 315-16.
[2779] Staff brief, p. 110.
[2780] 3 Tr 1533.
[2781] 3 Tr 1533-34.

amount of money spent for the Alma Equipment Repair sub-program has declined each year from 2021-2024[2782] and the Staff projected amount for 2025 is more analogous to the 2024 total than the 5-year average. This appears to be yet another sub-program where the Company is underspending and will not reach its projected total expense. This PFD recommends the Commission disallow $201,000 for Alma Equipment Repair O&M, as recommended by Staff.

iii. Field Operations

The Field Operations Program consisted of the cost of training, supervision, facilities, and facilities maintenance for the Company's in-field operations teams. This program included labor expenses for supervision and leadership for electric LVD and HVD operations. Expenses included the cost of training, supervision, facilities, and facilities maintenance for in-field operations teams.[2783]

Training

The Training sub-program covered expenses whenever groups in the Electric Operations organization conducted official training courses, generally at the Company's Marshall Training Center or another designated training location, typically with a course instructor. The Training O&M sub-program also included expenses for operating the Company's Apprenticeship Program, including paychecks earned by apprentices while they were at the training center.[2784] Mr. Kelly testified that the Company projected to spend $15,833,000 in the test year, based on the number of employees, apprentices,

[2782] Exhibit A-124.
[2783] 3 Tr 1538-39; Exhibit A-125.
[2784] 3 Tr 1539-40.

and external candidates, multiplied by the expected hours of training they would receive each year.[2785]

Ms. York next addressed Consumers' projected test year O&M expense for the Training sub-program. She noted that the Company determined expenses for this sub-program based on the number of employees, apprentices, and external candidates, multiplied by the expected hours of training they would receive each year.[2786] Ms. York stated that the projected test year spend was significantly in excess of historical amounts.[2787] Additionally, she stated that it remained unclear what assumptions the Company had made with respect to the new number of employees, apprentices, and external candidates that would actually require training during the projected test year, and whether that projection was reasonable and likely to be accurate.[2788] In order to address her concerns, Ms. York recommended reducing the Company's projected test year O&M expense by $4.793 million, bringing this projected test year spend closer in line with the five-year average.[2789]

The Company disputed Ms. York's characterization of the testimony related to challenges in obtaining necessary crews, noting that the challenges ABATE referenced had no bearing on the distribution workforce that his testimony supports. Mr. Kelly also stated that Ms. York was incorrect in focusing on the number of "new employees, apprentices, and external candidates that would actually require training during the projected test year." The Training O&M sub-program provided training for employees at

---

[2785] 3 Tr 1540; Exhibit A-125.
[2786] 6 Tr 3685.
[2787] 6 Tr 3685.
[2788] 6 Tr 3686.
[2789] 6 Tr 3686.

various stages of employment, including “union labor associated with additional hours of training, such as continuing education and required annual training courses.”[2790] Therefore, as with other O&M sub-programs, Ms. York recommended a disallowance based on the “Other Adjustments” amount.[2791]

In its brief, the Company addressed ABATE’s proposed reduction arguing that the Commission should reject this recommended reduction because it fails to recognize that the Company will need to increase training in the test year for the increased field operations workforce.[2792]

In its brief, ABATE notes the Company’s five-year average historical costs for this category were approximately $10 million and its 2024 actual costs were $11 million, the Company has here requested cost recovery of $15.8 million. As the Company failed to adequately support this significant increase the Commission should reject this requested cost recovery. Although the Training O&M subprogram must accommodate mandatory regulatory and safety requirements, the Company must provide granular support for its requested revenue increase, especially when the “Other Adjustments” column in supporting documents drives a significant portion of the proposed increase. Without clear evidence of incremental cost structure beyond historic averages and generalized workforce growth the Company has not met its burden and Commission should not approve the Company’s full requested amount. As such the Commission should reduce the Company’s projected test year O&M expense by $4.793 million,

[2790] 3 Tr 1604-5; Exhibit A-222.
[2791] 3 Tr 1604; Exhibit A-128.
[2792] Company brief, p. 319.

which adjustment would bring this projected test year spend closer in line with the five-year average.[2793]

This PFD concurs with the Company that adjustments based on "Other Adjustments" would not be appropriate absent additional justification and recommends the Commission not disallow expenses on that basis alone. The Company disputed ABATE's characterization of the testimony related to challenges in obtaining necessary crews, and the focus on "new employees, apprentices, and external candidates that would actually require training during the projected test year." The Training O&M sub-program provided training for employees at various stages of employment, including "union labor associated with additional hours of training, such as continuing education and required annual training courses."[2794] ABATE raises a legitimate concern regarding the significant increase in projected spending for the bridge period and projected test year; however, there was insufficient evidence to discredit the Company's projected spend.

Tools

The Tools O&M sub-program included the cost of procuring tools valued under $1,000. The Tools O&M sub-program also included expenses related to tool repairs. Some tools, such as fire-retardant clothing and other personal protective equipment were essential for employee safety and were required by OSHA regulations. Mr. Kelly testified that the Company projected spending of $1,982,000 in the test year based on the size of the field operations workforce.[2795]

[2793] ABATE brief, p. 69.
[2794] 3 Tr 1604-5; Exhibit A-222.
[2795] 3 Tr 1541-42; Exhibit A-124.

Staff witness Durfee provided Staff recommendations regarding the Company's projected expenses for the Tools sub-program, which were: 2025 - $1,497,000; 12 months ending 4/30/2027 - $1,982,000. The Company spent $448,000 in the first 6 months of 2025.[2796] Staff agreed that the Tools sub-program was necessary to acquire the tools needed to complete field work to improve reliability and restore service. However, given that the Company had only spent a fraction of what was needed to meet the projected spend in 2025, Staff recommended adjusting the projected expenses. Assuming linear monthly spend, the actual expenses for the first six months of 2025 were projected to get to a total spend for 2025 of $896,000 ($448,000*2). Applying a 2.40% inflation factor for 2026 and 2027, Staff projected an expense of $925,000 (($896,000*1.024*0.667)+($896,000*1.024*1.024* 0.333)) for the 12 months ending 4/30/2027 and recommended a disallowance of $1,057,000 ($1,982,000-$925,000).[2797]

The Company again stated 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.[2798] Mr. Kelly stated that it would be 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 was essentially in line with this level, and the Commission should approve the Company's projection.[2799]

In its brief, the Company addressed Staff's recommended reduction based on the Company's actual spending in the first six months of 2025 arguing that projecting future

---

[2796] 6 Tr 4432; Exhibit S-16.2; Exhibit A-124.
[2797] 6 Tr 4433.
[2798] 3 Tr 1580.
[2799] 3 Tr 1585.

spending levels based on actual spending in the first six months of 2025 fails to account for variation in spending that can occur within a year or from year-to-year. The Commission should approve the requested Tools funding to support the Company's ability to safely and efficiently restore outages, complete reliability projects, and install new services.[2800]

In its brief, Staff recommends reducing field operations – Tools O&M expense by $1,057,000 based on the Company provided year to date spend in those sub-programs being only a fraction of the projected spend for 2025.[2801]

For the Tools O&M sub-program, the Company projected spending of $1,982,000.[2802] The Company's five-year average for the Tools O&M sub-program is $1,634,000.[2803] In the last six years, the Company has not spent less than 1,256,000 on Tools O&M.[2804]Considering the Staff recommendation and the Company's historic spending in this category, this PFD recommends the Commission disallow $726,000 ($1.982-$1.256) from the Tools O&M sub-program. However, this PFD notes with caution that the linear arguments of both Staff and the Company are generally insufficient to support a favorable recommendation.

Underground Workforce

The Underground Workforce Program was responsible for both the undergrounding work in subdivisions and new business services, relocations, and reliability projects, plus future undergrounding the Company expected to pursue through

---

[2800] Company brief, pp. 317-18.
[2801] Staff brief, p. 110.
[2802] Exhibit A-125.
[2803] Exhibit A-124.
[2804] Exhibit A-124.

the Reliability Roadmap that was proposed to resume in the test year of the instant case. Mr. Kelly testified that the Company project test year spending of $2,236,000, was based on the workforce necessary to perform undergrounding for new business and failure work and the workforce necessary for future undergrounding the Company expected to pursue through the Reliability Roadmap.[2805]

Staff witness Durfee provided Staff recommendations regarding the Company's projected expenses for the Underground Workforce sub-program, which were: 2025 - $1,113,000; 12 months ending 4/30/2027 - $2,236,000. The Company also spent $292,000 in the first 6 months of 2025.[2806] Staff agreed that the Underground Workforce sub-program was necessary. However, given that the Company had only spent a fraction of what was needed to meet the projected spend in 2025, Staff recommended adjusting the projected expenses. Assuming linear monthly spend, the actual expenses for the first six months of 2025 were projected to get to a total spend for 2025 of $584,000 ($292,000*2). Applying a 2.40% inflation factor for 2026 and 2027, Staff projected an expense of $603,000 (($584,000*1.024*0.667)+($584,000*1.024*1.024*0.333)) for the 12 months ending 4/30/2027 and recommended a disallowance of $1,633,000 ($2,236,000-$603,000).[2807]

The Company stated 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.[2808] The Company asserted that it would be particularly inappropriate to assume linear monthly spending in this sub-program based on the first half of 2025. Mr. Kelly

---

[2805] 3 Tr 1546; Exhibit A-124.
[2806] 6 Tr 4433; Exhibit S-16.2; Exhibit A-124.
[2807] 6 Tr 4433-34.
[2808] 3 Tr 1580.

stated that in the test year the Company planned to complete 50 miles of overhead to underground ("OHUG") conversions, a workplan that Staff supported 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 Mr. Kelly asserted that the Commission should approve the Company's projection.[2809]

Mr. Coppola also addressed the Company's proposal to accelerate conversion of overhead lines to underground and the related capital expenditures on behalf of the Attorney General. He specifically addressed Mr. Kelly's discussion of the undergrounding pilot project from Case No. U-21389, the comparative net present value costs of undergrounding overhead lines versus other options, showing that undergrounding was the most expensive option versus other alternatives, and a comparison of costs for the four alternatives after imputing societal costs based on the ICE calculator.[2810] Mr. Coppola then testified that there were several problems with the Company's undergrounding proposal. First, the criteria outlined by the Company had relatively low thresholds that could result in hundreds if not thousands of overhead lines that could qualify for conversion to underground. Second, the criteria did not include a cost/benefit analysis (CBA) to determine whether the conversion was economic versus other options for each project. Third, the results of the pilot program showed a calculated average cost of $443,079 per comparable mile of overhead line converted to underground. Fourth, Mr. Kelly's testimony showed that even at the average cost per mile undergrounding was not a sound economic practice.[2811] Mr. Coppola then testified

---

[2809] 3 Tr 1585-86.
[2810] 3 Tr 2439.
[2811] 3 Tr 2439-41.

that the Company's proposal to undertake an expanded conversion of overhead lines to underground had not been well defined, it lacked important criteria to ensure that sound economic decisions were made, it was based on a misleading average cost per mile of overhead line to be converted to underground and should be rejected.

The Attorney General recommended that the Commission remove the incremental capital spending of $1,250,000 proposed by the Company for the bridge period and the $20 million for the projected test year.[2812] Mr. Coppola also recommended the Commission remove capital expenditures of $4,118,000 from both the bridge period and projected test year.[2813] Mr. Coppola further recommended that the Commission remove $5,368,000 for the bridge period and $24,118,000 for the projected test year from the Company's forecasted capital expenditures related to the resiliency sub-program.[2814]

Mr. Coppola also assessed the EGLE-MIEJ Undergrounding projects, noting that the Company included forecasted capital expenditures for three EGLE-MIEJ Undergrounding projects in Grand Rapids, Flint, and Kalamazoo for the bridge period totaling $4,118,000 and the same amount for the projected test year. In discovery, the Company reported that the three projects are in the scoping phase, which was the preliminary phase of development with no design or other advanced work performed. Therefore, the Attorney General assessed the costs and timing of the projects as still preliminary and premature for inclusion in rate base in this rate case and recommended

---

[2812] 3 Tr 2442.
[2813] 3 Tr 2443.
[2814] 3 Tr 2444.

that the Commission remove the capital expenditures of $4,118,000 from both the bridge period and projected test year.[2815]

The Company asserted that while OHUG was more expensive than alternatives at scale, OHUG was only 2% more expensive on average, and provided a 90% reliability improvement because the threat of trees would be almost eliminated. Therefore, Mr. Kelly asserted that OHUG still represented good value for the money.[2816] In response to the Attorney General's concern with the potentially large number of overhead line miles that could theoretically be eligible for OHUG projects, Mr. Kelly emphasized that the Company only sought approval for 50 miles of work in the instant case. Mr. Coppola also referred to the Commission's June 12, 2025 Order in Case No. U-21305, which called for "additional evidence, including a BCA" 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 indicated that the Commission did not expect separate benefit cost analyses for each individual project, but only one analysis covering OHUG as a program, which the Company indicated was provided in the Company's net present value analyses.[2817] In response to Mr. Coppola's dismissal of the SCT, Mr. Kelly stated that the Company's distribution strategy was not based on identifying the maximum outage duration that customers can endure and allowing customers to experience that.[2818] The Company has shown that OHUG was a competitive (using the UCT) or even superior (using the SCT) economic alternative for

[2815] 3 Tr 2443.
[2816] 3 Tr 1587.
[2817] 3 Tr 1587-88.
[2818] 3 Tr 1588.

improving reliability and resiliency; and the Attorney General's recommendation should be rejected because the $1,250,000 for OHUG in the bridge period was simply carry-over of pilot costs for work completed in the bridge period that was approved in Case No. U-21389.[2819]

In response to Mr. Coppola's $4,118,000 recommended disallowance for the ECLE-MIEJ Undergrounding Secondary and Services projects, the Company indicated it would not contest the proposed reduction in capital expenditures for the projects but noted the disallowance would necessitate removal of the corresponding grant amounts which would reduce those negative numbers by $1,349,000 for the bridge period and $2,698,000 for the test year and put that amount back into the Company's rate base for those periods.[2820]

Mr. Bunch, of CUB, also addressed Mr. Kelly's testimony on undergrounding. In Mr. Kelly's testimony, the Company proposed undergrounding 50 miles in the test year.[2821] CUB asserted that the Company did not justify the scope of the company's proposed underground because Kelly did not assess the costs and benefits of individual proposed undergrounding projects.[2822] CUB testified that half of the projected benefits of this program would be realized from a small minority of the 50 miles proposed. Given how expensive undergrounding was, Mr. Bunch stated the Company should focus its learning and cost-curve efforts on the few projects that have encouraging cost-benefits prospects.[2823]

[2819] 3 Tr 1588.
[2820] 3 Tr 1588-89.
[2821] 6 Tr 4061.
[2822] 6 Tr 4061.
[2823] 6 Tr 4062.

CUB used the Company outline of the benefits that each undergrounding project was expected to yield, the yearly estimates of the average cost of interruption to its customers for 2025 through 2032, and the Company's discount rate to calculate the net present value of avoided outages for each project through 2032 and concluded the for the entire proposed program, the eight-year present value of avoided outages for residential customers is $689,700.[2824] CUB went on to state that the benefits were very unevenly distributed among the proposed projects with half the benefits realized from only 11.3 of the 50 miles of undergrounding proposed.[2825] To determine the scope of 11.3 miles, CUB divided the eight-year present value of avoided customer outages by the number of miles being converted for each project, sorted the present value per mile and calculated a cumulative benefit to determine at what point approximately half of the program's benefits were realized.[2826] CUB recommended the Commission reduce the scope of the program to specific high-impact projects so that revenue requirement impacts were limited. This reduction would result in a disallowance of $15,480,000 in the test period.[2827]

CUB also stated that the Company did not perform a benefit cost analysis for each proposed OHUG project. Mr. Kelly referred to his response to Mr. Coppola on BCA. CUB then explained his evaluation and conclusion that half the benefits were tied to just 11.3 of the Company's proposed 50 miles of projects and recommended that the Company's OHUG work in the test year be limited to these 11.3 miles.[2828] The Company

---

[2824] 6 Tr 4062.
[2825] 6 Tr 4062-63.
[2826] 6 Tr 4063.
[2827] 6 Tr 4065.
[2828] 3 Tr 1615.

noted that CUB's model was incomplete because it was based solely upon the present value of avoided interruption costs to customers from an undergrounding project and ignored many of the costs included in a BCA such as Return on Equity, interest, depreciation, taxes, O&M that customers would pay in return for the improved reliability benefits, and ignored the costs of alternatives to undergrounding the feeder like continued vegetation management.[2829] The Company concluded that CUB misused the Interruption Cost Estimate ("ICE") calculator and understated the value of the project's impact on avoided interruption costs to customers given his analysis did not take into consideration the costs of alternatives.[2830]

Mr. Fitzhenry, from ABATE, also testified regarding the Company's Overhead to Underground conversion program, noting that while the Liberty audit recommended delaying the plan, the Company had decided to move forward with the program based on the positive results of the pilot, which demonstrated the cost-effectiveness and reliability benefits of undergrounding. The Company proposed $1.25 million in bridge period capital expenses for Overhead to Underground Conversions and $20 million in the test year.[2831] Mr. Fitzhenry noted that according to the Company's own data and using the Utility Cost Test ("UCT"), undergrounding was the most expensive option when compared to Aerial Spacer Cable including Forestry, Tree Wire Including Forestry, and Existing Overhead Including Forestry using the utility cost test ("UCT"). However, the Company also provided the results of a Societal Cost Test ("SCT"), which demonstrated that Undergrounding was the least cost option. The SCT used a lower

[2829] 3 Tr 1615.
[2830] 3 Tr 1615-16.
[2831] 6 Tr 3725-26.

discount rate than the UCT, which assigned more value to benefits further out in the investment lifecycle, when the benefits were more speculative.[2832]

Mr. Fitzhenry expressed concerns regarding the methodology deployed by the Company in both the UCT and SCT and noted that the Company had not demonstrated that Undergrounding was consistently the preferred solution using both cost tests.[2833] Mr. Fitzhenry expressed concerns regarding the Company's proposed undergrounding program, noting the Company was already having issues completing specific circuits identified for undergrounding, problems that would only be exacerbated when the program was increased by 45 times its current size. In addition, if the Company changed its proposed projects from one circuit to another due to issues with landowners, the benefits of undergrounding in the alternate circuit may not be as great as the benefits in the originally identified circuit, further reducing the cost-effectiveness of the program and lowering the benefits shown in the Company's UCT and SCT.[2834]

Mr. Fitzhenry concluded that the Company's proposed large-scale overhead to underground conversion program should be rejected. The reliance on the societal cost test to justify the program was speculative, as it places a high value on long-term, uncertain benefits. Additionally, the lack of demonstrated ability to efficiently execute the program, coupled with the uncertainty of cost and benefits, made the current proposal imprudent. Mr. Fitzhenry recommended that the Commission follow the recommendation of the Liberty audit and require the Company to complete and thoroughly analyze the initial pilot projects before committing to a massive capital

---

[2832] 6 Tr 3727.
[2833] 6 Tr 3727.
[2834] 6 Tr 3728.

expenditure. This recommendation would reduce the Company's test year capital expenditures by $20 million.[2835]

The Company asserted that Mr. Fitzhenry never clearly stated what his concerns were making it difficult to effectively rebut his position.[2836] However, OHUG was only 2% more expensive and expected to provide at least a 90% reliability improvement. Mr. Kelly further asserted that Mr. Fitzhenry's only apparent criticism of the SCT was that it was "speculative," and he did not provide any support for why the SCT was inappropriate to use.[2837] The Company also disagreed with Mr. Fitzhenry's comments on the OHUG pilot, asserting that a hallmark of a successful organization was that it can make adjustments and adapt as challenges arise. He stated that the Company only proposed scaling to 50 miles in this proceeding.[2838]

In its brief, the Company asserts that the Underground Workforce O&M expense funds workforce needed to complete undergrounding work in subdivisions and new business services, relocations, and reliability projects, plus the additional undergrounding work that the Company has proposed in this case. The Company's projected spending includes $1.106 million for new business and failure work, and $1.130 million for the new OHUG conversions proposed for the test year, which it recommends the Commission approve.[2839]

In response to Mr. Coppola's criticism of the OHUG conversions, which the brief reiterates, the Company argues that it is not struggling to develop its OHUG conversion

---

[2835] 6 Tr 3728-29.
[2836] 3 Tr 1599-1600.
[2837] 3 Tr 1600.
[2838] 3 Tr 1601.
[2839] Company brief, pp., 318.

approach.[2840] Based on lessons learned, the Company argues that the Commission should reject Mr. Coppola's removal of additional funding for undergrounding work in the bridge period and test year.[2841]

The Company addressed ABATE's recommendation to remove $20 million in the test year funding for undergrounding, rebutting each point.[2842] Having addressed the Attorney General, ABATE, and CUB recommendations against the undergrounding expense, the Company asserts the Commission should approve the requested funding for these projects to allow the Company to move forward with improving reliability for these customers.[2843]

The Company next addressed the Attorney General's recommended removal of $4.118 million in the bridge period and the test year for the EGLE-MIEJ Undergrounding projects because of his contention that the projects are still preliminary. Consumers Energy agreed not to contest this proposal, but noted if these expenditures are removed from the test year, then the corresponding grant amounts should also be removed from the total, reducing those negative numbers by $1.349 million in the bridge period and $2.698 million in the test year.[2844]

In its brief, Staff recommends reducing field operations – underground workforce O&M expense by $1,633,000 based on the Company provided year to date spend in

[2840] Company brief, pp. 58-9.
[2841] Company brief, p. 60.
[2842] Company brief, pp. 60-1.
[2843] Company brief, pp 60-2.
[2844] Company brief, p. 62.

those sub-programs being only a fraction of the projected spend for 2025.[2845] Staff did not address the EGLE-MIEJ underground project or OHUG conversions in its brief.

In her brief, the Attorney General addresses OHUG conversions and the EGLE-MIEJ Undergrounding. The Attorney General asserts the Company's proposal to undertake an expanded conversion of overhead lines to underground has not been well defined, it lacks important criteria to ensure that sound economic decisions are made, it is based on a misleading average cost per mile of overhead line to be converted to underground and should be rejected. Therefore, the Attorney General recommends that the Commission remove the incremental capital spending of $1,250,000 proposed by the Company for the bridge period and the $20 million for the projected test year.[2846]

The Attorney General then addresses the EGLE-MIEJ undergrounding projects for the bridge period totaling $4,118,000 and the same amount for the projected test year.[2847] The costs and timing of the projects are still preliminary and too premature for inclusion in rate base in this case. Therefore, the Attorney General recommends that the Commission remove the capital expenditures of $4,118,000 from both the bridge period and projected test year.[2848]

In its brief, MNSC argues that most of the expected benefits can be realized from a small minority of Consumers' proposed projects. Bunch recommends that the Commission should, in test year 2026, limit the scope of Consumers' undergrounding program to projects with only the highest reliability impacts, saving ratepayers as much as $15,480,000. the costs and benefits of individual undergrounding projects are highly

[2845] Staff brief, p. 110-15.
[2846] Attorney General brief, p. 65.
[2847] Attorney General brief, pp. 65-6.
[2848] Attorney General brief, p. 66.

variable and cannot be easily generalized.[2849] After reiterating Mr. Bunch's testimony, MNSC argues that the Company did not sufficiently justify its proposals to increase undergrounding projects in the test year and beyond.[2850] MNSC argues that the Company's argument that a single BCA is sufficient is not correct; rather, while the Commission said a BCA is necessary, they did not say or suggest a single BCA would be sufficient. The surrounding context indicates that it the Commission did not mean a single programmatic BCA would suffice.[2851] Without individual BCAs for individual undergrounding projects, it is impossible to evaluate proposed undergrounding against other reliability programs on an apples-to-apples basis.[2852] MNSC also argues that the Company's critique of Mr. Bunch's analysis is not persuasive.[2853] Therefore, MNSC recommends a reduction in scale of the Company's test year undergrounding program, approving only those 11.3 miles of high-impact projects identified by Mr. Bunch, saving ratepayers $15,480,000.[2854]

In its reply brief, MNSC argues that the Commission should not approve expensive underground conversions simply because it will provide avoided customer outage minutes. MNSC argues that the Company's proposed undergrounding projects will eliminate some customer outage minutes, those benefits are highly variable.[2855] Company Exhibit A-167 showed – and MNSC's initial brief highlighted – that the reliability benefits for individual projects range from 22,000 to 436,500 customer outage

---

[2849] MNSC brief, pp. 6-7.
[2850] MNSC brief, p. 8.
[2851] MNSC brief, p. 9.
[2852] MNSC brief, p. 10.
[2853] MNSC brief, pp. 11-12.
[2854] MNSC brief, p. 12-13.
[2855] MNSC reply brief, p. 1.

minutes avoided.[2856] The Company has the burden to produce enough information for the Commission to "fully evaluate the proposed undergrounding" projects against one another and against alternatives. To decide which reliability programs to prioritize and approve, the Commission needs information about projects' relative impacts and costs – information the Company did not present.[2857] MNSC reiterated CUB witness Bunch's testimony comparing the relative impacts of Consumers' projects and showing that over half of expected residential customer benefits can be "realized from only 11.3 of the 50 miles of undergrounding proposed" and at a fraction (23%) of the proposed cost. Using that information, the Commission should prioritize the highest impact projects, shrink the size of the undergrounding program, and save ratepayers $15,480,000 relative to the Company's initial proposal.[2858]

Staff, the Attorney General, CUB, and ABATE all provided recommendations on the Company's Underground Workforce sub-program. This PFD notes that the Company spent $713,000 in 2024, projected $1,113,000 for 2025, and requested $2,236,000 for the projected test period; however, Staff notes the year-to-date spend is a fraction of the amount projected.[2859] There is no five-year average due to the lack of a 2020 amount, but spending has roughly doubled for the last three years.[2860] The Company argues that "spending is not linear," a recurrent refrain in this case. This PFD finds that the Company needs to do a better job of showing how and in which quarter the actual and projected spending did and will occur to support its projected expenses.

[2856] MNSC reply brief, pp. 1-2.
[2857] MNSC reply brief, p. 2.
[2858] MNSC reply brief, p. 2.
[2859] Exhibit A-124.
[2860] Exhibit A-124.

Therefore, this PFD recommends the Commission disallow $1,633,000, as recommended by Staff, based on the Company provided year-to-date spend in those sub-programs being only a fraction of the projected spend for 2025.

As to the Attorney General's recommendation on OHUG, seconded by MNSC (CUB) and ABATE, this PFD recommends the Commission reject the Attorney General's recommendation to disallow $20 million for the projected test year because the Company provided sufficient evidence to rebut the collective criticisms of the Company's OHUG program.

The Company agreed not to contest the Attorney General's recommendation to remove the funding for the EGLE-MIEJ Undergrounding projects. Therefore, this PFD recommends the Commission remove the associated funding and grant amounts from the bridge period and the test year.

b. Electric Engineering & Support

The Electric Engineering O&M was separated into the following programs: Engineering Support; Electric Distribution Management; Electric Distribution – LVD; Electric Distribution – HVD; Electric Distribution Strategy; and Wildfire Mitigation.[2861]

Electric Distribution – LVD

The Electric Distribution – LVD Program covered salaries and expenses for the Company's LVD Engineering organization, which included the Company's LVD Planning, LVD Design, Joint Pole Rental, and Grid Automation teams. LVD Planning expenses primarily included the O&M portion of salaries, business expenses, and

[2861] 3 Tr 1550; Exhibit A-126.

training for LVD Planning employees.[2862] LVD Design expenses primarily included the O&M portion of salaries, business expenses, and training for LVD Design personnel. Joint Pole Rental included expenses associated with jointly using poles with other utilities (e.g., telecommunications). The Grid Automation team consisted of personnel primarily responsible for planning and developing the Company's Grid Automation programs and projects. Mr. Kelly testified that the Company projected Electric Distribution – LVD expenses of $11,773,000 in the test year. This was an increase from earlier years, and it was largely attributable to the increased amount of LVD planning and LVD design work necessary to support the increased number of LVD projects being identified as part of the Reliability Roadmap.[2863]

The Company forecasted that the Electric Distribution – LVD O&M expense would increase from $7.3 million in 2024 to $11.0 million in 2025 and $11.8 million in the projected test year. Mr. Coppola noted that this covered salaries and other expenses for the LVD engineering organization which includes LVD planning, design, joint pole rental expenses, and the Grid Automation teams.[2864] The Company stated that over the past five years, expenses in this area have ranged from $5.8 million to $8.6 million with the most recent year (2024) at $7.3 million. Mr. Kelly attributed the large increase to additional projects identified as part of the Reliability Roadmap.[2865] In discovery, the Company showed the total expense for the first eight months of 2025 at $3.243 million, which was an annualized expense level of $4,865,000 - well below the actual 2024 level of $7,254,000 and well below the Company's projected test year expense. Moreover,

[2862] 3 Tr 1551-52; Exhibit A-124.
[2863] 3 Tr 1552; Exhibit A-124.
[2864] 3 Tr 2580.
[2865] 3 Tr 2580.

the Attorney General noted that the tasks performed in this area had been ongoing for some time, which led her to conclude that the rationale for a large ramp-up of expenses was not supported by Mr. Kelly's testimony. Therefore, the Attorney General recommended that the Commission should set the expense at the 2024 level of $7,254,000 and reduce O&M expense for the projected test year by $4,519,000 from the $11,773,000 forecasted by the Company.[2866]

The Company rejected Mr. Coppola's recommendation and testified that the projected increase tied to Grid Automation was not related to ongoing work, noting that Mr. Coppola did not state how he came to that conclusion or how he defined ongoing work. Because the Company's increase in this sub-program was driven by new Grid Automation work, Mr. Kelly asserted that it would not be appropriate to index the spending level to a historical amount as recommended by Mr. Coppola.[2867]

In its brief, the Company addressed Mr. Coppola's proposed reduction stating that the Commission should reject the recommended reduction because the projected work in this sub-program is to support the new work that will be performed in LVD projects and Grid Automation. The Company asserts that the Commission should approve the Company's projection based on the actual projected increase in work needed in this sub-program.[2868]

In the Attorney General's brief, she asserts that the tasks performed in this area have been on-going for some time and therefore the rationale for a large ramp-up of

---

[2866] 3 Tr 2580-81.
[2867] 3 Tr 1594.
[2868] Company brief, p. 320.

expenses does not appear to be supported by the Company's testimony.[2869] Therefore, the Attorney General recommends that the Commission set the expense at the 2024 level of $7,254,000 which reduces the O&M expense for the projected test year by $4,519,000.[2870]

This PFD notes that the increase in the Electric Distribution – LVD O&M expense is significant; however, the Company has provided adequate justification for the increased expenditure in this sub-program. The company forecasted that the Electric Distribution – LVD O&M expense would increase from $7.3 million in 2024 to $11.0 million in 2025 and $11.8 million in the projected test year. The Company attributed the increased expense to the increased amount of LVD planning and LVD design work necessary to support the increased number of LVD projects being identified as part of the Reliability Roadmap. It is also attributable to increased Grid Automation work to support the programs and projects described in the testimony of Mr. McPhail.[2871] The Company stated that over the past five years, expenses in this area have ranged from $5.8 million to $8.6 million with 2024 at $7.3 million.[2872] Therefore, this PFD is persuaded by the Company's testimony and recommends no disallowance for this sub-program, but it does recommend the Commission direct the Company to show how this money was spent in its next rate case.

[2869] Company brief, p. 176.
[2870] Company brief, p. 176.
[2871] 3 Tr 1553.
[2872] Exhibit A-124.

2. Line Clearing O&M Expense

Consumers is requesting $186,684,000 in O&M for the Line Clearing Program for the projected test year with $22,238,107 for an LVD ramp-up to be deferred to a regulatory asset and the remaining amount to be recovered in rates.[2873]

Company witness Stewart explained that the Line Clearing Program is divided into HVD line clearing and LVD line clearing.[2874] She explained that the HVD program contains four subprograms, which are: 1) "maintenance clearing" where trees are scheduled for trimming or removal to maintain minimum separation distances within or outside the ROW; 2) "brushing and herbicide treatment" which consists of brush cutting and herbicide treatment to reduce the volume of small trees growing within the ROW and maintain habitat for endangered, threatened, or rare species; 3) "demand clearing," which addresses emergent vegetation threats identified during inspections or helicopter patrols; and 4) "noxious weed control" to maintain compliance with local ordinances on fee-owned HVD ROW in predominantly urban areas.[2875]

As for the LVD program, Ms. Stewart testified that it is comprised of seven subprograms: 1) "program maintenance," which conducts scheduled clearing on full circuits to maintain minimum separation distances; 2) "repetitive outage zonal clearing," which targets specific sections of circuits that are experiencing high levels of tree-caused outages identified during monthly reviews of non-MED (major event day) outages; 3) "CEMI (customers experiencing multiple interruptions) clearing," which targets selected areas upstream of the customer location; 4) "first zone clearing," which

[2873] 3 Tr 2231, Fig. 23; Ex. A-170.
[2874] 3 Tr 2186.
[2875] 3 Tr 2187-2189.

targets the section of a circuit from the substation outward to logical load concentration points (LCPs); 5) “LCP zonal clearing,” which was created in 2024 to comply with the Settlement Agreement in Case No. U-21224 and targets the worst performing zones across the LVD system; 6) “demand clearing,” which addresses emergent vegetation threats to the LVD system identified by customers, forestry operations personnel, and other field personnel; and 7) “brush control,” which uses herbicide applications to treat brush within the LVD ROW two to three years following full circuit clearing, particularly on rural and suburban circuits.[2876]

According to Ms. Stewart, Consumers has maintained a four-year line clearing cycle on its HVD system since 2020.[2877] However, while the Company has worked toward an effective seven-year cycle on its LVD system, it has only been able to achieve an average effective cycle of 10.2 years over the five-year period 2020-2024.[2878] She presented Exhibits A-172 and A-173, which contained Consumers’ 2025 HVD line clearing and LVD line clearing workplans, respectively.[2879]

She asserted that Consumers is proposing to maintain the four-year clearing cycle for the HVD system and ramp up to a five-year cycle on the LVD system, with more aggressive line clearing on targeted three phase primary lines.[2880] She described the five-year cycle strategy as clearing one-fifth of the Company’s LVD line miles annually and maintaining the standard that all LVD circuits have been fully cleared

---

[2876] 3 Tr 2189-2193.
[2877] 3 Tr 2195, Fig. 1.
[2878] 3 Tr 2196, Fig. 2.
[2879] 3 Tr 2195, 2196.
[2880] 3 Tr 2198.

within a five-year period.[2881] She explained that Consumers proposes to eliminate all backlog miles (circuits that have not been fully cleared within five years) by the end of 2030-2031 and then maintain steady-state cycle maintenance while reevaluating other tactics for continuous improvement in risk management.[2882]

She asserted that as the LVD system grows nearer to being on a five-year cycle, the necessity of partial circuit clearing subprograms (repetitive outage zonal clearing, CEMI clearing, first zone clearing, LCP zonal clearing) lessens and therefore these subprograms will be phased out starting in 2026 and through 2030-2031.[2883] She testified that after 2030-2031 when the LVD system is projected to be fully on-cycle, Consumers will only perform these activities on mid-cycle circuits if the need arises, which is consistent with other utilities, such as Alliant Energy, Ameren Missouri, and American Electric Power, which Consumers considers its benchmarking partners[2884]

Ms. Stewart indicated that the reason Consumers' is changing from a seven-year effective cycle to a five-year cycle is to comply with the recommendations in the Liberty Audit, as well as previous Commission orders.[2885] She maintained that Consumers is meeting the Liberty recommendation to achieve a shorter cycle length of four or five years, but it is not operationally feasible to meet Liberty's aggressive timeline to achieve the shorter cycle by year-end 2028.[2886] She opined that achieving a five-year cycle by

---

[2881] 3 Tr 2199.
[2882] Id.
[2883] 3 Tr 2200.
[2884] Id.
[2885] 3 Tr 2201-2202.
[2886] 3 Tr 2202.

the end of 2030-2031 reflects an operationally feasible timeline that is just two to three years longer than Liberty's recommendation.[2887]

She maintained that Consumers has complied with the Commission's Order in Case No. U-21389 to file a Formal Optimization Analysis of line clearing cycles.[2888] She stated that the analysis found that six to seven years is the optimal cycle length, considering the costs for residential customers.[2889] Nonetheless, she asserted that Consumers is proposing a five-year cycle length based upon Staff's concerns and Liberty's recommendation.[2890]

She testified further that Consumers has analyzed more aggressive line clearing tactics, as required in Case No. U-21389 and discussed in Case No. U-21585, and is proposing to implement canopy removal on a portion of the LVD system.[2891] She explained that canopy removal eliminates all branches over primary lines regardless of clearance distance, tree species, or health of limb.[2892] She testified that Consumers is proposing canopy removal on 10% or roughly 5,500 miles of overhead primary on the LVD system, targeting the three phase portions of circuits that have the highest consequence of failure due to serving the most downstream and/or critical customers.[2893] She acknowledged that this does not directly match what was presented in Case No. U-21585, where zones and number of phases were used to differentiate

---

[2887] Id.
[2888] 3 Tr 2202; Ex. A-176.
[2889] 3 Tr 2203.
[2890] 3 Tr 2203-2204.
[2891] 3 Tr 2204.
[2892] Id.
[2893] 3 Tr 2206.

between more aggressive line clearing options.[2894] But she testified that targeting circuits with the highest consequence of failure will inherently include the first and some second zones, and may extend past the second zone depending on zone attributes.[2895] She added that as outlined in Case No. U-21585, 100% of customers fed by LVD lines are served within and downstream of first zones, which comprise about 6% of total LVD miles and it is not uncommon for electric utilities to have more aggressive clearing specifications in early zones versus later zones.[2896]

She testified that removing canopy on targeted LVD three phase lines encompasses sections of line that are projected to provide the greatest impact to overall customer reliability for the incremental expense.[2897] She noted that in 2022, the Company performed a small canopy removal study on approximately 42 miles of three phase primary which resulted in an observed average contractor cost increase of 35% per mile cleared.[2898]

She asserted that Consumers plans to measure the reliability impact of the proposed targeted canopy removal and is considering including this analysis in its Case No. U-20697 Line Clearing Program annual reports. However, she added that the Company does not expect to have statistically significant data sets until 2027 and therefore, measurement of the reliability impact of the proposal would appear at the earliest in the 2028 report.[2899]

[2894] Id.
[2895] Id.
[2896] 3 Tr 2206-2207.
[2897] 3 Tr 2206.
[2898] 3 Tr 2204-2205, Figs. 5 and 6.
[2899] 3 Tr 2207.

Ms. Stewart described Consumers' proposed Tree-caused Outage Review program, explaining that the purpose of the program is to gather data on a subset of LVD tree-caused outages and determine the top causal contributors, establish and monitor trends, and inform future line clearing strategy decisions.[2900] She testified that Consumers is proposing to review outages that meet the following criteria: 1) non-MED; 2) circuit lockout and/or primary outage; 3) cause code of Trees or Trees - Outside ROW; and 4) greater than or equal to 500 customers impacted. She stated that over the last five years, an annual average of about 250 outages met these criteria.[2901]

Ms. Stewart described Consumers' line clearing proposal to mitigate wildfires. She explained that in Case No. U-21585, Consumers proposed implementing a five-year line clearing cycle in elevated wildfire risk areas to better manage growth and limit potential vegetation to conductor contact. However, because the Company is proposing a shorter five-year cycle for the entirety of its LVD system, line clearing in elevated wildfire risk areas is no longer an incremental expense.[2902] Nonetheless, she testified that Consumers is proposing a more aggressive timeline in wildfire risk areas, namely, achieving the five-year cycle for circuits in relatively high wildfire risk areas by year-end 2026 and by year-end 2028 in moderate wildfire risk areas.[2903] She added that as part of Consumers' planned technology enhancements it is conducting a small pilot to capture Light Detection and Ranging (LiDAR) imagery as proposed in Case No. U-21585 to support LVD line clearing tactics in relatively high-risk wildfire areas and is

[2900] Id.
[2901] 3 Tr 2208.
[2902] Id.
[2903] 3 Tr 2208-2209.

proposing to continue this pilot annually and then expand it to a larger scope.[2904] She added that Consumers is also exploring the use of drone technology and researching multiple sensor packages (e.g., multispectral, infra-red, and LiDAR) for targeted inspections and documentation of vegetation along the electric system.[2905]

Ms. Stewart described the reliability benefits of Consumers' Line Clearing Program. She testified that trees are the greatest cause of interruptions to electric service for customers on the LVD system and a significant cause of outages or interruptions on the HVD system.[2906] She testified that the program is designed to minimize these occurrences, improve reliable service to customers, and decrease reactive maintenance and capital expense associated with interruptions during weather events.[2907] She maintained that the five-year cycle strategy will yield significant improvement to customers' electric service and provide benefits that are not easily quantified, such as improved habitat for many plants and animals, including threatened and endangered species, and decreased risk of wildfires. She added that Consumers' proposals will result in less aesthetic impact to customer properties, as clearing will occur more frequently, and will improve public safety.[2908]

Ms. Stewart supported Consumers' requested line clearing funding. She asserted that it will enable the maintenance of the four-year HVD line clearing cycle and minimize outages across the system. She explained that the HVD system is the foundation and source for the LVD system and outages on the HVD system can have

---

[2904] 3 Tr 2209.
[2905] 3 Tr 2210.
[2906] 3 Tr 2210-2211, Fig. 7.
[2907] 3 Tr 2210.
[2908] 3 Tr 2211.

broad impacts affecting large numbers of customers.[2909] She noted that from 2020 through 2024, the average customer impact of a non-MED tree outage incident on an LVD circuit was 45 customers and the average customer impact of a non-MED tree outage incident on an HVD line was 471 customers. Additionally, she testified that outages on the HVD system often take longer to repair and therefore have higher customer minute impacts.[2910]

As for the LVD Line Clearing Program, she stated that the requested spending will support a more aggressive plan of increasing the number of miles cleared each year, which will result in a decrease in the number of tree-related outages to the LVD system. According to Ms. Stewart, the Company projects that by 2030, MED tree-caused primary outage incidents will decrease by 30%, leading to a 27% and 29% reduction in SAIFI and SAIDI, respectively.[2911]

Regarding canopy removal, Ms. Stewart testified that based on benchmarking data, Consumers is estimating a 4% reduction in primary tree-caused incidents from canopy removal on targeted three phase lines.[2912]

She testified that the reliability benefits of the LVD five-year cycle will be fully realized through the second clearing cycle, or roughly by 2036.[2913] She noted that Liberty attributed more significant reliability improvement in the second cycle to a lack of clearing completeness within the first cycle. She stated that while Consumers agrees that it will likely not see full reliability benefits until the second clearing cycle, it does not

---

[2909] Id.
[2910] Id.
[2911] 3 Tr 2212-2214, Figs. 8-10; Ex. A-171.
[2912] 3 Tr 2216-2217; Ex. A-177.
[2913] 3 Tr 2214.

agree that this is because its line-clearing work is incomplete.[2914] Rather, she opined, the partially delayed benefit may be driven by a lack of "wind firmness" in the surrounding healthy trees, which is the ability of trees to sway with strong winds without breaking or toppling.[2915] She testified that Consumers plans to utilize the proposed tree-caused outage review program to determine if wind firmness is causing a significant impact to outages post-clearing.[2916]

Ms. Stewart maintained that Consumers considered the benefits of shifting to a four-year fixed line clearing cycle as directed by the Commission in Case No. U-21585, but believes the five-year cycle is the next prudent step.[2917] She testified that Consumers compared the costs and benefits of achieving a four- and a five-year line clearing cycle in the same ramp-up strategy period it is currently proposing and the results indicated that achieving a four-year cycle could raise expenses nearly 15% overall, with some years as high as 23%, and only result in 3% of additional reliability benefit across multiple metric types due to diminishing returns.[2918] She noted that to increase line clearing miles in the current ramp-up timeframe, the majority of the incremental expense is due to increasing out-of-state tree crewing, which is more expensive than local tree crewing.[2919] Ms. Stewart opined that while the incremental cost of moving from a five-year cycle to a four-year cycle may be prudent in the future, it currently is not. She added that once the five-year cycle is attained, Consumers will

---

[2914] Id.
[2915] 3 Tr 2214-2215, citing My Land Plan, American Forest Foundation (American Forest Foundation, How Windstorms Affect Your Forest, My Land Plan, https://mylandplan.org/content/how-windstorms-affect-your-forest.
[2916] 3 Tr 2215.
[2917] Id.
[2918] 3 Tr 2215-2216.
[2919] 3 Tr 2216.

reevaluate other tactics for continuous improvement in risk management, including cycle considerations.[2920]

Ms. Stewart described the expenses and cost components of Consumers' line clearing proposals. She presented historical and projected annual costs and other data for the LVD and HVD programs from 2020 to 2030.[2921] She presented Consumers' projected total O&M Line Clearing expense for the test period of $186,683,974, which includes $11,064,347 for Admin.[2922] Ms. Steward testified that Admin includes the internal salaries and expenses of the Company's Forestry Operations Department and also includes contract foresters and contract work planners.[2923] She added that all contractor rates are limited through mid-2029 to an annual adjustment maximum of 2.5% per year based on the Producers Price Indices WPUFD4 and WPU443.[2924]

Ms. Stewart testified that total HVD line clearing expenses, including admin expenses, are projected to be $11.840 million and Consumers is requesting to recover the entirety of it in base rates.[2925] She noted that in Case No. U-21585, Consumers requested $12.240 million for HVD line clearing.[2926]

Ms. Stewart presented Consumers total LVD Line Clearing forecasted spending of $174.844 million (including admin of $9,980,209).[2927] She noted that the expense for canopy removal on targeted three phase lines is $4.172 million for the 2026 calendar year, which was calculated using an average contractor cost increase of 35% per mile

---

[2920] Id.
[2921] 3 Tr 2217-2218, Figs. 11 and 12.
[2922] 3 Tr 2220-2221, Fig. 14; Ex. A-170.
[2923] 3 Tr 2220.
[2924] 3 Tr 2221, Fig. 15.
[2925]3 Tr 2222-2223, Fig. 16; Ex. A-170.
[2926] 3 Tr 2222.
[2927] 3 Tr 2223, Fig. 17; Ex. A-170.

cleared, as observed in the 2022 canopy removal study.[2928] She noted that the Commission approved expenditures for LVD line clearing of $71 million in Case No. U-20697 and $113 million in Case No. U-21585.[2929] She maintained that Consumers has met its commitment to spend the authorized amounts for the Line Clearing Program in its recent rate cases.[2930]

She testified that Consumers is proposing regulatory asset treatment for the LVD Line Clearing O&M funding requirement for the test period that is above baseline expenditures of $164,445,867 ($11,839,660 for HVD line clearing and $152,606,207 for LVD line clearing) to be recovered in base rates, with the remaining $22,238,107 to be deferred to a regulatory asset.[2931] She stated that the baseline of $164.446 million was calculated using the annual baseline beyond 2030-2031 and then adjusting it to test period dollars.[2932] She explained that the LVD portion of the baseline, which is $152.606 million, is different than what the Company estimated as an annual expense to maintain the LVD system on a five-year cycle in its Formal Optimization Analysis because refined and updated assumptions were used, including overall crew resourcing, and the consideration of overtime for both local and out-of-state tree crews.[2933]

She explained that average monthly spending is not consistent during a significant ramp-up period and as a result, the Company's test period projection for this case (May 1, 2026 through April 30, 2027) was not calculated using ratios of eight

---

[2928] 3 Tr 2224-2225, Fig. 18.
[2929] 3 Tr 2225, Fig.19.
[2930] 3 Tr 2226, Fig. 20, referring to Case Nos. U-20697, U-20963, U-21224, U-21389, and U-21585.
[2931] 3 Tr 2231, Fig. 23; Ex. A-170; See the section of this PFD addressing regulatory asset approvals for more details.
[2932] 3 Tr 2218-2219, Fig. 13.
[2933] 3 Tr 2219.

months of the 2026 calendar year and four months of the 2027 calendar year, but instead was driven by operational intelligence derived from managers and staff and informed by historical costs per mile cleared, current system work estimates, crew availability and work schedules, and other factors.[2934] She testified that if the HVD workplan is completed under budget, any remaining dollars for the test year will be allocated to the LVD system.[2935]

Ms. Stewart described line clearing unit costs. She maintained that Consumers' data shows that a shorter clearing cycle results in a lower average cost per mile, while longer cycles result in more complex clearing work and require the removal of more biomass, as the vegetation has had more time to grow between clearings. Therefore, she testified that Consumers based its projections to maintain the five-year cycle on lower unit costs.[2936] She explained the variation in unit costs from 2020 to 2024, noting that unit costs decreased significantly in 2020 because of decreased customer interactions due to the pandemic and increased 2021 to 2024 primarily due to contractor costs.[2937]

Ms. Stewart testified that Consumers currently has the resources in place to maintain the HVD system on a four-year clearing cycle. However, the Company has not yet secured the personnel and other resources required to execute the full requested spending level for LVD Line Clearing.[2938] She asserted that while Consumers will not execute its plans to secure additional personnel and other resources until funding

---

[2934] 3 Tr 2227; Ex. A-170.
[2935] 3 Tr 2228.
[2936] 3 Tr 2228-2229, Fig. 21.
[2937] 3 Tr 2229-2231, Fig. 22.
[2938] 3 Tr 2231-2232.

certainty is attained, the Company is preparing to do so for the test period, focusing on line clearing contractors, contract planning and supervision, and internal staffing.[2939] She testified that Consumers expects to have an additional 92 contractor line clearing crews to meet the crewing level needed in the 2026 calendar year to clear an estimated 7,891 miles in the LVD full circuit clearing (program maintenance) subprogram, which is 1,783 more miles (29% higher) than projected for 2025.[2940]

Ms. Duell testified that Staff supports the requested $186,684,000 for the projected test year O&M expense for the Line Clearing Program. She added that "[i]t is crucial to allow Consumers to spend the full amount for line clearing to increase the resiliency of Consumers Energy's electric distribution system."[2941] Ms. Duell stated that Staff also supports the Company's proposal to recover LVD line clearing ramp-up spending as a regulatory asset, noting that the Commission approved a regulatory asset for DTE's tree trimming surge program.[2942]

Ms. Duell criticized Consumers' past line clearing efforts. She asserted that the Company did not follow the Commission's order in Case U-21585 to consider the benefits of a four-year cycle based on the Company's Formal Optimization Analysis but instead proposed to shift to a five-year cycle.[2943] She also noted that the Company has circuits that have not been cleared in 37 years.[2944] Based on these past deficiencies,

---

[2939] 3 Tr 2232-2233, Fig. 24.
[2940] 3 Tr 2234.
[2941] 6 Tr 4388.
[2942] 6 Tr 4389.
[2943] 6 Tr 4390.
[2944] Id.

Staff is recommending that the return on the line clearing regulatory asset be set at Staff's short term debt rate.[2945]

Ms. Duell testified that Consumers needs to improve its current line clearing practices and dedicate more resources to the program to deliver the reliable service customers deserve.[2946] She recommended that Consumers change its current practice of removing first zone tree canopy on a case-by-case basis to removing 100% of tree canopy in the first zone. She maintained that this is what DTE and other utilities do and Consumers would see decreased outages if it adopted this practice.[2947] As for canopy removal in other zones, Ms. Duell expressed Staff's support for the proposal to remove 10%, or 5,500 miles, of canopy on targeted LVD three phase lines.[2948] She asserted that these two changes to Consumers clearing specifications will provide increased reliability and she recommended that that they be adopted.[2949]

Ms. Duell observed that there were discrepancies between Consumers' testimony and its discovery responses regarding how much tree canopy is removed in the first zone. She noted that Ms. Stewart's testimony seemed to suggest that the Company cleared all canopy in the first zone, but the Company's discovery responses indicated that this is not the case.[2950] According to Ms. Duell, this demonstrates that Consumers is not being clear and detailed when providing testimony and she asserted

---

[2945] 6 Tr 4389-4390, see the section of this PFD addressing regulatory asset approvals for more details.
[2946] 6 Tr 4391-4392.
[2947] 6 Tr 4391.
[2948] 6 Tr 4392.
[2949] Id.
[2950] 6 Tr 4392-4393.

that Staff would like to see Company witnesses be clearer and more detailed when writing testimony for future rate cases.[2951]

Ms. Duell testified further that Staff is concerned that Consumers did not meet its projections for line clearing in miles trimmed or funds spent in 2024. She explained that in Case No. U-21585, the Company projected spending $105,371,000 on LVD line clearing, while in this case, the Company shows it spent only $99,494,748.[2952] And she asserted the Company failed to respond to Staff's question asking where the remaining $5,876,252 went.[2953] Ms. Duell stated that "[i}f the Company cannot provide Staff with detailed information regarding where unspent funds are being reallocated to then Staff may recommend disallowances in future rate cases."[2954] Additionally, she noted that Consumers trimmed fewer miles in 2024 than it projected and when asked why in discovery Ms. Stewart stated:

> The Company's projected 6,760 miles of LVD line clearing was estimated prior to execution of new LVD contracts in May 2024. The impact of the new LVD line clearing contracts is discussed in my direct testimony on page 47, lines 21 through 22, and page 48, lines 1 through 2. Higher unit costs per mile resulted in fewer O&M miles cleared for the budget amount. Additionally, the Company made operational decisions during the 2024 calendar year that resulted in less spend toward line clearing for the calendar year while still meeting its test year spend target toward line clearing as defined in the Order for MPSC Case No. U-21389.[2955]

Ms. Duell testified that line clearing is one of the most important programs in any electric company's portfolio and if Consumers is experiencing contractor shortages, Staff is

---

[2951] 6 Tr 4393.
[2952] 6 Tr 4393-4394; Ex. A-170.
[2953] 6 Tr 4394; Ex. S-18.
[2954] 6 Tr 4394.
[2955] 6 Tr 4394; Ex. S-18.

concerned that it will not achieve a five-year line clearing cycle by 2030/2031.[2956] She emphasized that it is extremely crucial that Consumers increase its contracting crews for line clearing since its line clearing program is already behind and Staff does not want the Company to fall even further behind due to contractor shortages.[2957] She recommended that Consumers spend the entire amount of line clearing expenses approved in each rate case it files and completes all line miles that are being proposed to be trimmed each year.[2958]

Ms. Duell acknowledged Ms. Stewart's testimony that Consumers considered and compared the costs and benefits of a fixed four-year line clearing cycle, but she noted that the Company relied on the Formal Optimization Analysis and did not provide a new analysis as required by the Commission in Case No. U-21585 and as expected by Staff.[2959] As a result, she recommended that Consumers file a new analysis of the costs and benefits of a four-year cycle with its next rate case and Staff would like the Company to:

> to provide an O&M exhibit sheet showing the costs of moving to a 4-year cycle, provide contractor costs associated with moving towards a 4-year effective cycle, provide detailed information on the availability and securing contracts for line clearing contractors with a 4-year cycle, and cost savings associated with moving towards a 4-year effective line clearing cycle.[2960]

ABATE witness York testified that she is concerned that Consumers' projected test year spending on HVD line clearing is overstated. She noted that the total line clearing projection of $186.684 million represents an increase of $76.459 million or

---

[2956] 6 Tr 4394-4395.
[2957] 6 Tr 4395.
[2958] 6 Tr 4393.
[2959] 6 Tr 4395-4396.
[2960] 6 Tr 4396.

approximately 69% from actual 2024 spending amounts and the Company's projection of $11.840 million for the HVD portion of the program is an increase of about $10.586 million or 12% over the historical average from 2020 to 2024.[2961] She also noted that Figure 1 from Ms. Stewart's testimony reveals that from 2020 to 2024, Consumers consistently underspent on HVD Line Clearing by about 10%, while it still cleared its planned number of miles each year.[2962] She also remarked that Ms. Stewart's Figure 11 shows that the Company is planning to clear a similar number of HVD miles each year through 2030 using the same number of crews used in the past.[2963] Based on her observations, she recommended a 10% reduction in the Company's HVD Line Clearing projection for the test year, which is a reduction of $1.184 million.[2964]

Mr. Bunch testified that Consumers' proposal to achieve a five-year line clearing cycle is consistent with the recommendations put forth in the Liberty Audit and to reach this target cycle the Company must devote significantly more spending compared to both historical spending levels and what will be required to maintain the five-year cycle, once realized.[2965] As a result, both he and Mr. Jester supported the Company's operational plan and spending level and agreed that line clearing surge, or ramp-up, costs should be held as regulatory assets.[2966] However, Mr. Bunch disagreed with the calculation of the ramp-up baseline.[2967]

[2961] 6 Tr 3686-3687.
[2962] 6 Tr 3687.
[2963] Id.
[2964] 6 Tr 3688, Table JAY-5.
[2965] 6 Tr 4052.
[2966] 6 Tr 4052, 3991.
[2967] 6 Tr 4052.

He testified that Ms. Stewart's method to establish the baseline of $164.446 million for the test year by taking the projection for the annual expense to maintain the five-year cycle after it is achieved and then adjusting it backward to test year dollars, is speculative and novel. He recommended that the baseline be calculated by taking 2024 historical line clearing spending and adjusting it by a productivity-adjusted inflation factor, or PAI factor, which results in projected test year spending, or a baseline for the ramp-up, of $113,977,000 and $72,707,000 being treated as a regulatory asset.[2968]

In rebuttal, Ms. Stewart addressed Ms. Duell's statement that Consumers did not prioritize its line clearing program highly enough in the past, contending that the since Case No. U-20697, the Company has exceeded authorized spending levels for line clearing and has remained transparent and committed to clearing the backlog and establishing the seven-year effective cycle.[2969] She also disagreed with Ms. Duell's statement that Consumers cleared fewer miles than proposed and underspent in line clearing in 2024. She explained that:

> 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.[2970]

She testified that in Case No. U-21389, the Commission authorized $118,889,334 for the Line Clearing Program for the test period, which was the 12

[2968] 6 Tr 4053, See the section of this PFD addressing regulatory asset approvals for more details.
[2969] 3 Tr 2237-2238.
[2970] 3 Tr 2238.

months ending 2/28/2025, while Consumers spent $119,189,032.[2971] Ms. Stewart referred to Exhibit S-18 and contended that Ms. Duell is incorrect in her statement that Consumers failed to answer Staff's question about the disposition of $5,876,252 of 2024 LVD line clearing funding. She opined that Ms. Duell may have unintentionally conflated the 2024 calendar year with the Case No. U-21389 test year.[2972]

Ms. Stewart clarified that Consumers is not experiencing contractor shortages, stating that her comments in discovery about 2024 LVD contracts causing higher unit costs "is not synonymous with a contractor shortage."[2973] She also testified that Ms. Duell is incorrect in her interpretation of the scope of Consumers' canopy removal proposal. Ms. Stewart maintained that while the Company's proposal will include some second zones and may even extend past the second zone, the zone number alone will not be the sole determining factor for canopy removal, but rather the driving factor will be the consequence of failure of the section of line in question.[2974] She explained that this will inherently include many first zones, as the Company targets the path of substation-to-substation connection to enable switching opportunities during outage events, but it may not include 100% of first zones depending on individual zone attributes.[2975]

She disagreed with Staff's recommendation that Consumers remove 100% of canopy in the first zone and asserted that she did not represent that the Company was

---

[2971] Id.
[2972] 3 Tr 2239.
[2973] 3 Tr 2239; Ex. S-18.
[2974] 3 Tr 2239.
[2975] 3 Tr 2239-2240.

proposing this.[2976] She maintained that Consumers' projected revenue requirement for line clearing would be insufficient if this requirement were added.[2977] However, she stated that Consumers is agreeable to considering 100% first zone canopy removal in the future after being able to evaluate its costs and benefits and she recommended that the Company be granted time to execute its proposed canopy removal and collect reliability data on the targeted three-phase lines.[2978]

Finally, Ms. Stewart disagreed with Ms. Duell's recommendation that Consumers be required to file a new analysis of the cost and benefits of a four-year cycle in its next rate case.[2979] She maintained that Consumers already conducted this analysis, which included projected costs, a timing assumption, and projected reliability improvement, and found that moving to a four-year cycle in the timeframe 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.[2980] She also contended that Consumers did not rely on the Formal Optimization Analysis, which assumed steady-state costs to maintain each cycle length analyzed, whereas the analysis in the instant case assumed the current state of the LVD system and projected costs to move it to a four-year cycle.[2981] She testified that the next prudent step in the evolution of Consumers' Line Clearing Program is the outlined five-year line clearing cycle and once it is attained, the

[2976] 3 Tr 2240.
[2977] 3 Tr 2240-2241.
[2978] 3 Tr 2241.
[2979] 3 Tr 2242.
[2980] 3 Tr 2241.
[2981] 3 Tr 2242.

Company will re-evaluate other tactics to improve risk management, including cycle considerations.[2982]

Turning to Ms. York's testimony, Ms. Stewart opposed her recommended 10% reduction of projected HVD line clearing expenses and disagreed that Consumers' HVD projection is overstated. She asserted that the 2026 HVD workplan includes clearing the same segments that were cleared in 2022 to maintain the four-year cycle, as well as nearby segments for improved crew efficiency, so there will be more miles cleared in 2026, than 2022. She also noted that Consumers executed new line clearing contracts in 2024 and experienced an increase in the base rates for line clearing contractors.[2983] She maintained that Consumers projects spending the full proposed test year amount for HVD line clearing, but if the HVD work is completed underbudget, the difference will be allocated to the LVD line clearing program. She explained that Consumers has followed this reallocation practice since 2020, and it should alleviate Ms. York's concerns.[2984]

As for the appropriate baseline for the ramp-up regulatory asset, Ms. Stewart explained that Consumers' test year baseline reflecting 12 months ending April 30, 2027, was calculated as 8/12th of 2026 and 4/12th of 2027 projected spending, but in practice, calendar year 2026 will be a transitional year in the ramp-up process, where the first four months will still operate under the previous seven-year effective cycle

[2982] Id.
[2983] 3 Tr 2236-2237.
[2984] 3 Tr 2237.

approved in Case No. U-21585 and the remaining eight months will reflect the ramp up to the new five-year cycle.[2985]

The Attorney General's brief and MNSC's brief generally recap their respective witnesses' testimony supporting Consumers line clearing proposals but arguing that a higher proportion of expenses should be deferred and the short-term debt rate should be applied to the proposed regulatory asset.

In its brief, Consumers recaps Ms. Stewart's testimony and emphasizes that its proposed line clearing expenses are higher than historical amounts would suggest since this is the first case incorporating the five-year LVD cycle length and where the Company has proposed the more aggressive tactic of canopy removal.[2986] Consumers expects that higher line clearing expenses will be the trend over the next five years, more than doubling between 2025 and 2030 as the Company continues to clear backlog circuits that are, on average, more expensive to clear, before declining and leveling out.[2987] Consumers argues that its canopy removal proposal is consistent with utility best practices and is scoped to stretch the Company's dollars to benefit the most customers possible for the incremental amount that will be spent.[2988] As for Staff's proposal to clear 100% of canopy in the first zone, Consumers states that the costs and benefits of the proposal are unclear and therefore it should be rejected, but the Company would consider it in future rate cases, as more information is obtained.[2989]

[2985] 3 Tr 2242-2243.
[2986] Consumers initial brief, p. 324.
[2987] Id., p. 325.
[2988] Id., p. 327-328.
[2989] Id., p. 327-328.

Consumers contends that its past line clearing practices are from “bygone eras” and the Company is confident in its recent progress under new leadership.[2990]

In its brief, Staff contends that it has reviewed Consumers’ rebuttal testimony and maintains its recommendation that Consumers clear 100% of canopy in the first zone, in addition to the Company’s proposal to clear 10% or 5,500 miles, of three phase overhead primary tree overhang in everything outside of the first zone.[2991] In other issues, Staff disagrees with Consumers’ assertion that it spent more than approved by the Commission for the 12 months ending 02/28/2025. Staff emphasizes that for calendar year 2024, Consumers underspent in LVD line clearing in the amount of $5,876,252 and cleared 695 less miles than was proposed in Case No. U-21585. Staff further argues that it is well within its rights to analyze costs on a historical calendar year basis, and if Consumers is asked questions regarding said expenses the Company should be able to answer fully and transparently.[2992] Staff also remains committed to its position that Consumers should spend the entire amount of line clearing expenses approved in each rate case and trim all proposed miles, and if unable to do so, explain where unspent amounts are being reallocated to when asked.[2993] Staff argues that Consumers’ discovery responses and its witness’s testimony implied it was unsure it would have enough contractors to complete the five-year effective cycle, however given Ms. Stewart’s rebuttal testimony, Staff will follow up on this issue in Consumers’ next rate case.[2994] Staff is also committed to its recommendation that Consumers file a new

---

[2990] Id., p. 329.
[2991] Staff initial brief, p. 140.
[2992] Id., p. 141.
[2993] Id., p. 142.
[2994] Id., p. 142-144.

four-year effective line clearing analysis, including the factors discussed by Ms. Duell. Staff opines that Consumers did not provide enough detailed information on moving to a four-year effective LVD line clearing cycle in this case.[2995]

In reply, Consumers asserts that is not necessarily opposed to Staff's proposal to remove 100% of overhang in the first zone, if it is first allowed to evaluate the costs and benefits of the proposal.[2996] Consumers maintains that it will have better data if the Commission approves its proposal to remove 5,500 miles of canopy, both within and outside the first zone, and emphasizes that its proposal is not limited to miles outside of the first zone and does not cover all miles outside of the first zone.[2997] Consumers contends that approving its plan as proposed will deliver the most benefits to customers for the cost.[2998] Concerning future line clearing spending, Consumers states that "it is not opposed to a requirement that it spend its approved line clearing expenses, but the Company should continue to have operational flexibility to accelerate or postpone plans to clear some line miles."[2999] Consumers asserts that it answered Staff's questions regarding calendar year spending to the best of its ability and does not understand what information Staff believes was withheld.[3000] Finally, Consumers maintains that while it has already performed an analysis of a four-year line clearing cycle, "it is certainly open to further analysis in the future," however the next rate case "is likely too soon."[3001]

[2995] Id., p. 144-145.
[2996] Consumers reply brief, p. 15.
[2997] Id.
[2998] Id.
[2999] Id.
[3000] Id., p. 15-16.
[3001] Id., p. 16.

Consumers contends that it should be allowed to make progress toward its proposed five-year cycle, "which is itself an immense undertaking."[3002]

This PFD finds that Consumers proposed test year O&M spending of $186,683,974 should be approved. Staff, the Attorney General and MNSC all support the level of spending and Consumers move to a five-year clearing cycle on the LVD system, and this PFD agrees that the spending is reasonable and prudent and will increase the resilience of Consumers' electric distribution system. This PFD also recommends approval of Consumers' request to defer $22,238,107 of the LVD expenses as ramp-up costs, using the short-term debt rate, and based on the Company's proposed baseline of $164,445,867, as discussed in more detail in the section of this PFD addressing regulatory asset approvals.

This PFD declines to adopt ABATE's recommendation to remove 10%, or $1.184 million, of proposed HVD line clearing expenses based on Consumers' projection that it will spend the full amount and its commitment to allocate any unspent funds to LVD line clearing. In agreement with Staff, this PFD finds that Consumers should spend the entire amount of line clearing expenses approved in this and each rate case and trim all proposed miles, and if unable to do so, explain how the unspent amounts were reallocated.

This PFD recommends approval of the undisputed aspects of Consumers' line clearing proposal, including the proposed Tree-Caused Outage Review Program and an accelerated timeline to achieve the five-year cycle in wildfire risk areas. This PFD recommends approval of Consumers' plan to clear 10% or 5,500 miles of three phase

---

[3002] Id.

overhead primary tree overhang on the LVD system and declines to adopt Staff's recommendation that Consumers also clear 100% of first zone canopy, agreeing with the Company that the costs and benefits of the work are currently unknown. This PFD is also concerned that this work could cause the Company to fall behind its ramp-up timeline based on Consumers' contention that current funding would be insufficient to support clearing all first zone canopy. However, this PFD finds merit in Staff's proposal and recommends that Consumers be required to collect available data on the costs and benefits of 100% first zone canopy removal from its benchmarking partner utilities and estimate the costs and benefits of such a plan and present its findings in its next rate case.

Turning to Staff's recommendation that Consumers file a new analysis of the costs and benefits of a four-year cycle for its LVD system with its next rate case, this PFD notes that in Case No. U-21585, the Commission seemed to express frustration that Consumers was proposing to move to a seven-year effective cycle and was resistant to consider shorter cycles. Based on this, the Commission stated:

> As such, the Commission expects Consumers to incorporate the results of the analysis underlying its own Optimization Analyses and directs the company to consider the benefits of shifting to a four-year fixed tree trimming cycle in its next electric rate case.[3003]

This PFD finds that Consumers did as the Commission directed and considered the benefits of shifting to a four-year fixed cycle on the LVD system, finding 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

---

[3003] Case No. U-21585, Order, March 21, 2025, p. 292.

benefits. Therefore, this PFD declines to adopt Staff's recommendation that Consumers file a new analysis of the costs and benefits of a four-year cycle with its next rate case. However, based on the Commission's Case No. U-21585 order that the four-year cycle may be the most optimal cycle, this PFD recommends that Consumers be required to study the costs and benefits of moving to a four-year cycle after it has achieved the five-year cycle on the LVD system to include the following: an O&M exhibit sheet showing the costs of moving to a four-year cycle; contractor costs associated with moving towards a four-year effective cycle; detailed information on the availability of securing contracts for line clearing contractors with a four-year cycle; and cost savings associated with moving towards a four-year effective line clearing cycle.

Also, this PFD agrees with Staff's concerns that contractor costs could cause Consumers to fall behind its line clearing ramp-up timeline and recommends that Consumers be directed to mitigate its contractor costs, such as by negotiating lower costs or by having Company crews perform more line clearing work.

3. Service Restoration

a. Service Restoration Expense

Company witness Snider testified that the Company's service restoration activities play a critical role in the timely restoration of service to customers during outages. He noted that timely recovery of service restoration expense was essential to ensuring resources were available to restore service as quickly as possible, as the Company would be challenged to achieve further improvements in storm restoration service if it did not have timely rate recovery for the costs associated with such

service.[3004] As predicted by the Company's climate change and weather modeling, customers experienced another record-breaking year in terms of response opportunities. In 2024, three catastrophic storms and two large gray sky events that occurred back-to-back in January, affecting 293K customers in one week, were the primary events. Despite the increase in storm activity and interruption volume, O&M service restoration costs decreased year-over-year from 2023 to 2024 by 17% with the cost per interruption decreasing by 18%.[3005] Additionally, the Company's System Average Interruption Duration Index ("SAIDI") excluding Major Event Days ("MEDs") improved 21.4 minutes to 155, and all-weather SAIDI improved from 913 to 502.6 minutes. The improvements in service restoration were a result of both the distribution system investments sponsored by Company witness Kelly and the CE-Way process of continuous improvement that Mr. Snider discussed in detail in Case No. U-21585.[3006]

All-weather restoration performance in EJ communities was 98.9% in 2024 in EJ communities compared to 97.7% in Non-EJ communities, 1.2% better than the Company's system average, with restorations made within 36 hours.[3007] In March of 2025, the Company developed reporting to provide increased visibility into the identification of circuits in EJ communities that were experiencing outages. This information is available in real time to the ICS teams and Grid Operators to assist with restoration prioritization.[3008]

[3004] 3 Tr 2123.
[3005] 3 Tr 2123-24.
[3006] 3 Tr 2124.
[3007] 3 Tr 2124.
[3008] 3 Tr 2125.

Mr. Snider testified that the Company acknowledged that even with strong improvement in 2024, customers deserve an even more reliable grid than the Company had last year. The Company, including the Service Restoration team, has a more aggressive goal for reliability as detailed in the Reliability Roadmap, which includes three resiliency stands:

1. Delivering reliability performance into the 2nd quartile of nationwide utilities.
2. Delivering a grid where no single outage event will affect more than 100,000 customers.
3. Delivering a grid where no customer will be without power for more than 24 hours following an outage event.

While achieving these goals remained a long-term work in progress; they serve as a useful guide to what the Company built through this rate case.[3009]

Mr. Snider stated the Company had already experienced two catastrophic storms in 2025. Both storms affected more than 300,000 customers and occurred just six weeks apart. The first event was a historic multi-wave storm event that affected much of the state of Michigan from late March into early April that meteorologists from the National Weather Service called, “the worst ice storm in modern times.” The event resulted in more than 8,500 outage incidents impacting over 380,000 Consumers customers, the seventh largest storm by outages in the Company’s history. The total cost of the storm was projected to exceed $133 million (O&M and Capital), which was a significant portion of the Company’s 2025 service restoration authorized spend from

[3009] 3 Tr 2125-26.

Case No. U-21585.[3010] The second event affected over 334,000 customers just six weeks after the historic ice storm. On the evening of May 15th, a severe line of thunderstorms struck the State, producing 11 tornados and hurricane strength wind gusts from Holland to Battle Creek, ultimately resulting in over 830 broken poles and 91 miles of conductor that required replacement. Total costs (O&M and Capital) from this event were estimated to exceed $60 million.[3011]

The recent catastrophic storms demonstrate the urgent need for timely rate recovery to keep the power on for customers, businesses, and communities, so the Company can respond to the 'New Normal' of severe storms in Michigan. The modeling predicted that this type of weather will become more frequent in the coming years, meaning the Company will likely have to protect and restore its customers from similar events on a more regular cadence.[3012]

The Commission opened Case No. U-21305 in October 2022 after severe weather in August of that year caused many long power outages, downed energized utility lines across the state, and threatened public safety. The Commission directed the audit to consist of physical inspection of the utilities' distribution system infrastructure and investigation of the utilities' organization, staffing, and resources used to operate and maintain their distribution systems and restore power when service is interrupted by severe weather. Following this process, the Liberty Audit was released on September 23, 2024.

[3010] 3 Tr 2126-27.
[3011] 3 Tr 2127-28.
[3012] 3 Tr 2128.

Mr. Snider testified that many recommendations in Audit were aimed at improving the Company's service restoration performance and had merit, which led the Company to begin making changes addressing these recommendations while it awaited a final order in Case No. U-21305.[3013]

Recommendation 4 proposed the Company evaluate its current outage model for effectiveness and consider developing a more robust product in-house or through a third-party vendor to provide more useful and impactful results. Mr. Snider stated the Company agreed with the Final Report recommendation that accurate outage modeling was critical for restoration staffing and planning for forecasted storm events and believed that more accurate outage predictions could improve the Company's storm restoration performance, including wire-down response. The Company has been working to improve its outage modeling results through two additional initiatives, which would enable the Company to make improvements in outage modeling capabilities:

New Third-Party Outage Model - The Company evaluated third-party vendor technologies that could potentially improve upon its outage modeling capabilities currently provided by IBM.

New In-House Outage Model – The Company planned to internally develop a standalone outage prediction model in partnership with the University of Michigan. This in-house model would provide the Company with another set of data to compare against outputs from the third-party outage model.[3014]

[3013] 3 Tr 2129-30.
[3014] 3 Tr 2130-31.

Mr. Snider noted the Company agreed with this recommendation and had a series of technology investment plans that would enable the Company to improve its outage modeling prediction accuracy beginning in 2025.[3015]

Recommendation 5 proposed that the Company make the act of event classification a catalyst to groups involved in restoration to prepare to address the needs associated with the anticipated impacts of the event and change, as necessary, after storm arrival, to reflect new weather-related developments and resultant changes. Mr. Snider testified that the Company has appropriate processes and procedures in place to meet the intent of this recommendation.[3016]

Mr. Snider noted predicted customer outages and estimated resource needs dictate storm event classification; storm event classification does not dictate resource needs. The value and significance of a storm event was the predicted customer outages and estimated resource needs, not the storm incident level by itself. While storm event classification may be useful as a trigger for certain storm related activities, the predicted customer outages and estimated resource needs serve as the foundational information that drives all storm restoration-related activities.[3017] The Company planned for storm events on a weekly basis to prepare for a weather event's impact, which were communicated to its stakeholders. In November 2024, Mr. Snider stated the Company hired a full-time Meteorologist to provide tailored weather forecasts, specific to the Company's distribution grid and the state of Michigan. Every week the Company prepared for the subsequent week's potential storm responders from an ICS

[3015] 3 Tr 2131.
[3016] 3 Tr 2132.
[3017] 3 Tr 2133-34.

perspective. Storm preparedness communications began every Thursday and storm preparation related information would be documented in ICS Form 201, with a Daily Communication Report providing storm preparation and planning updates to relevant stakeholders across the organization.[3018] Mr. Snider noted the Company corrected the ICS Level categorization data when it was finalized for MPSC reporting purposes.[3019]

Recommendation 6 proposed the Company track resource requests from specific contractors (or mutual assistance), request timing, and what resources were provided to assist in post-event analysis, process improvement, and internal training.[3020] Since the execution of Consumers Energy's storm contracts which began on June 1, 2023, Mr. Snider indicated the Company had implemented or refined mechanisms to track, manage, and retain requests for resources to respond to service restoration events.[3021] Mr. Snider also addressed Recommendations 9 and 10 from the Liberty Audit, noting the Company's proposed bridge period and test year O&M expense aligned with Final Report recommendations by ending reliance on a five-year historical average and basing the projected expense on the Company's 2024 actual Service Restoration expense adjusted for inflation.[3022]

Mr. Snider noted that the Company currently identified and classified outage causes on its system using the Institute of Electrical and Electronics Engineers' (IEEE) standard outage cause codes, including the following: animals, equipment, trees,

[3018] 3 Tr 2134.
[3019] 3 Tr 2135.
[3020] 3 Tr 2136.
[3021] 3 Tr 2136-37.
[3022] 3 Tr 2137-39.

unknown, and weather.[3023] In its report, Liberty observed that the "weather" cause code "masks the actual cause of outages like trees, lightning, or ice . . . ." Similarly, it said that the "unknown" cause code is not precise but nonetheless "accounts for 11 percent of total interruptions."[3024] The Company agreed that there was value in reducing the use of "weather" and "unknown" cause codes and discussed the initiatives then underway to improve how it identified and classified outages. Mr. Snider stated that to better comply with IEEE standards, the Company was making changes to training, controls, and other operational processes.[3025] He further stated that the Company planned to complete process changes, including new quality assurance and quality control processes, by the end of the year. More accurate outage data would help the Company better plan its resources to restore power after outages while also enabling better planning for its Reliability Roadmap.[3026]

Mr. Snider stated the Company's projected service restoration O&M expense for the bridge period was $214.3 million and the projected expense for the test year in this case was $165.2 million.[3027] Given that 2024 O&M spending was a lagging indicator (although with far less lag than the five-year average), the bridge period and test year funding was calculated by inflating the historical year 2024 for the years 2025, 2026, and 2027. For the bridge period, the calculation included all of calendar year 2025, plus four months of 2026, the sum of which equaled the bridge period amount of $214.3 million. The calculation for the test year considered eight months of the year 2026 and

[3023] 3 Tr 2156.
[3024] 3 Tr 2156.
[3025] 3 Tr 2157.
[3026] 3 Tr 2157.
[3027] 3 Tr 2139.

four months of the year 2027, the sum of which equaled the test year amount of $165.2 million.[3028]

Mr. Snider testified that Service Restoration has been underfunded in each of the previous five years, for a total funding gap of $351 million. The most recent five-year average from 2020 through 2024 would have produced a test year total of approximately $148 million that the Company projected would be insufficient to deliver the improved service restoration that customers deserve. As the Company faces increasingly severe weather, Mr. Snider asserted that relying on a backward-looking average that has been explicitly rejected by an independent audit threatened to undo the progress made by the Company.[3029] Prior year spending was the most accurate benchmark of trending weather and current system capabilities, based on the unpredictable weather explained in the Scenario and Investment Planning section of the Company's Reliability Roadmap.[3030] He stated the Company's recommended approach was to re-baseline to the most recent year, which most accurately represented all variables in their current state. Mr. Snider testified that through the creation of the Resiliency Fund the Company would ensure every dollar was allocated specifically for customer service restoration or returned to customers as a credit.[3031]

Mr. Snider asserted that the Company had been prudent with restoration dollars with results demonstrated by its historic year's performance and documented in Service Quality and Reliability Standards filings. In 2024, the duration of catastrophic storms in the Company's service territory, as measured by the average length of storm days, was

[3028] 3 Tr 2140.
[3029] 3 Tr 2141.
[3030] 3 Tr 2141.
[3031] 3 Tr 2142.

3.3 days compared to a five-year average of 5.5 days. This accounted for a 2.1 day or 61% reduction in catastrophic storm duration resulting in an improved customer experience.[3032] Liberty noted the Company's restoration performance, measured by the average duration of classified storm types, shows marked improvement in recent years across all storm classifications except for Catastrophic.[3033] Mr. Snider testified that the proposed test year O&M proposal reflected the 2024 actual Service Restoration expense adjusted for inflation, which the Company believed provided the most accurate benchmark for service restoration requirements.[3034]

Ms. Duell addressed the Company's service restoration expenses. She noted that the main purpose of the service restoration program was to restore electric service to customers in a timely and efficient manner. It was important that the Company use all available resources to make sure its customers did not have to suffer without electricity, particularly during the cold and hot months of the year.[3035] Ms. Duell reviewed the Company's projected test year service restoration O&M expenses of $165,200,000 on behalf of Staff and recommended approval of $165,200,000 for the projected test year service restoration O&M expense.[3036]

Mr. Coppola testified that the new approach veered from the long-standing practice of using an average of the last five years of restoration expense to set the forecasted amount for the projected test year. The five-year approach normalized and evened out peaks and valleys in the annual expense to avoid large fluctuations in the

---

[3032] 3 Tr 2142.
[3033] 3 Tr 2142.
[3034] 3 Tr 2143.
[3035] 6 Tr 4398.
[3036] 6 Tr 4398.

projected test year expense instead of solely on the expense incurred in the most recent year, as Mr. Snider has done under his new approach. Mr. Coppola asserted that Mr. Snider's approach was flawed and should be rejected.[3037] Using the actual service restoration expenses for the five years from 2020 to 2024, Mr. Coppola calculated the average expense amount of $137,666,000, adjusted this amount by the inflation rates for 2025 to the end of the projected test year and arrived at the adjusted forecasted expense of $144,572,000. This amount is $20,643,000 less than the $165,213,000 forecasted by the Company. The Attorney General then recommended that the Commission adopt the traditional calculation Mr. Coppola presented and disallow $20,643,000 from the Company's forecasted O&M expense for the projected test year.[3038]

In rebuttal, Mr. Snider asserted that the Attorney General's proposed disallowance of $20.6 million for Service Restoration test year O&M because the Company's requested methodology veered from the practice of using a five-year average of restoration expenses to set the test year amount did not take into consideration that the historical method was challenged by Liberty in their independent audit and had resulted in a $351 million gap in funding over the past five years.[3039] As a result, the Company stopped relying on a five-year historical average and based the proposed bridge period and test year O&M amounts on the 2024 historic year expenses. Mr. Snider asserted that this approach provided the most accurate benchmark based on projected service restoration performance requirements and when

---

[3037] 3 Tr 2571-72.
[3038] 3 Tr 2572.
[3039] 3 Tr 2169.

paired with the proposed Service Restoration Resiliency Fund ("Resiliency Fund"), it alleviated the Attorney General's concern that the Company's proposed approach did not "even out peaks and valleys in the annual expense."[3040]

In its brief, the Company reiterates Mr. Snider's testimony and the recommendation from the Liberty audit that "[r]eliance on five-year historical costs to establish restoration budgets should end."[3041] The Company avers it is re-baselining its restoration budget, as Liberty recommended, to base the projected expense on its 2024 actual service restoration expense adjusted for inflation – the most recent year of historical data available. By doing so, the Company is using the most accurate benchmark available.[3042] The Company asks the Commission to approve $165.2 million to support its efforts in the test year, which Staff supports and which is in line with Liberty's findings.[3043] The Company urges the Commission to reject the Attorney General's proposed service restoration expense and adopt the Company's projected expense that Staff supported and no other party has opposed.[3044]

In its brief, Staff states its support for the Company's proposal to spend $165,200,000 in the projected test year O&M expense in service restoration.[3045]

In her brief, the Attorney General reiterates relevant testimony and recommends that the Commission adopt the traditional method of calculating the expense as

---

[3040] 3 Tr 2170.
[3041] Company brief, p. 336.
[3042] Company brief, p. 337.
[3043] Company brief, p. 339-40.
[3044] Company brief, p. 340.
[3045] Staff brief, p. 195.

performed by Mr. Coppola and remove $20,643,000 from the Company's forecasted O&M expense for the projected test year.[3046]

This PFD is not persuaded by the Attorney General's argument. Using historical methods of calculating service restoration expenses has chronically underfunded service restoration. The Liberty audit specifically recommended moving away from using historical costs to establish restoration budgets, which the Company did with its projected service restoration O&M expense. The Company's expense is also fully supported by Staff and has drawn no additional objections. Therefore, this PFD recommends the Commission reject the Attorney General's proposed disallowance and approve the Company's projected test year O&M expense in service restoration.

b. Service Restoration Resiliency Fund

Mr. Foster testified about the recommended Service Restoration Resiliency Fund. The Service Restoration Resiliency Fund would allow the Company to record a regulatory liability when the actual projected test year expense was lower than the rate case authorized service restoration O&M. The regulatory liability would act as a reserve to support service restoration expenses in future years when actual O&M exceeded the rate case authorized O&M. The Fund would be capped at $30.7 million to ensure that the fund only preserves the dollars needed to respond to a potential catastrophic event, after which customers would see a financial benefit from the Company's efficiency. The cap limit was based on the average O&M costs for a catastrophic storm for the past three historic years (2022, 2023 and 2024). The average storm cost was then adjusted for inflation based on the 2.4% inflation rate supported by Company witness Daly as

[3046] Attorney General brief, p. 180.

part of this case. The Company would propose a refund method in its next electric rate case for any underspent dollars that cause the regulatory liability to exceed the cap of $30.7 million.[3047]

Mr. Snider introduced the Service Restoration Resiliency Fund (SRRF), stating that it ensured every customer dollar allocated for service restoration was used for service restoration or returned to customers as a credit. The Resiliency Fund would be a reserve of surplus service restoration dollars from any prior year that would be used as the first source of funds when actual costs for service restoration exceed base spend levels. The fund would be capped at $30.7 million in the test year, with any dollars exceeding those levels refunded to customers through a bill credit.[3048] If the Commission approved the SRRF, any unspent dollars from the approved amounts for the test year would be transferred to the Service Restoration Resiliency Fund. Those dollars could be used to support service restoration expenses in future years when additional funds are needed and would function as the first option to fund any restoration activity beyond base funding levels.[3049] The cap limit was based on the average O&M costs for a catastrophic storm for the past three historic years (2022, 2023, and 2024). The average storm cost was then adjusted for inflation based on the 2.4% inflation rate. Because the weather is unpredictable, the Company set this limit to ensure that the fund only preserved the dollars needed to respond to a single potential

[3047] 6 Tr 3366-67.
[3048] 3 Tr 2143.
[3049] 3 Tr 2144.

catastrophic event, after which customers would see a financial benefit from the Company's efficiency.[3050]

Mr. Snider testified that currently in the event of an underspend for Service Restoration, the Company would re-allocate the O&M resources to other projects with no guarantee that customers would see any reimbursement. Whereas, if approved, the SRRF would both earmark approved funds for service restoration in the years to come when the need arises or be returned to the customer.[3051] Re-baselining suggests there is a higher likelihood of underspend. Coupled with the Company's restoration improvements, the Company maintains that there would be an increased likelihood of underspend from the prior year baseline. In support of the Resiliency Fund, Mr. Snider noted that it comes at no additional cost to customers—it was simply a rainy-day savings plan, ensuring all dollars allocated for service restoration were spent on service restoration or refunded. Together with annual re-baselining, customers would see immediate benefits from any year's savings in the next baseline, while savings were also captured in the Resiliency Fund for no other reason than to benefit customers, literally, on a rainy day.[3052]

c. Extraordinary Storm Accounting

Mr. Foster then testified about the proposed Extraordinary Storm Accounting (ESA), which would allow for deferred accounting treatment for service restoration costs for severe storms once actual service restoration costs exceed amounts included in rates and any Service Restoration Resiliency Fund has been depleted. Storms that

[3050] 3 Tr 2145.
[3051] 3 Tr 2146.
[3052] 3 Tr 2146-47.

would qualify for deferral under this proposal are storms that cause at least 300,000 customer outages (16.6% of Consumers Energy customers) or storms that result in a State of Emergency declaration from the Governor's office.[3053] Any amounts deferred under this mechanism would be recorded to a regulatory asset and the Company would support the deferred amounts for recovery in its next electric rate case.

Mr. Snider then addressed the Company's proposed Extraordinary Storm Accounting (ESA). The ESA would allow the Company to use deferred accounting for service restoration costs for extraordinary storms that exceed base spending levels. The Company defined "extraordinary storms" as storms that cause at least 300,000 customer outages over a seven to 10-day period or that result in a State of Emergency declaration from the Governor's office. Under the Company's proposal, expenses in response to extraordinary storms would qualify for deferred recovery.[3054] Extraordinary storms, which present challenging restoration conditions and cause significant damage to Company assets, were the main cause of increased service restoration spending and pose the largest risk to sustainable service restoration operations.[3055] When these storms pass through the Company's service territory, even perfect execution of pre-planning and restoration procedures could still result in a costly, multi-day restoration effort costing over $100 million.

Mr. Snider asserted that as disruptive and costly as these storms are, they are fundamentally unpredictable; therefore, requiring the Company to bear the full brunt of their impact in a single year without allowing for deferred storm accounting, was not only

---

[3053] 6 Tr 3367.
[3054] 3 Tr 2147.
[3055] 3 Tr 2148.

unreasonable but also counterproductive to ensuring a reliable and resilient grid. As a result, Mr. Snider testified that preparing for a future where weather events like the March/April storms are more frequent required establishing deferred accounting where the Company could apply for timely rate recovery in response to these events.[3056] The Company then noted that the Liberty Audit Final Report recognized that deferral accounting for excess storm costs may offer a solution for avoiding customer costs for adverse weather that does not materialize, while preventing significant Company economic loss when such weather requires significantly more than costs included in revenue requirements for ratemaking purposes.[3057] Mr. Snider then noted other states use deferred accounting for O&M costs caused by severe weather.[3058]

Mr. Snider then explained that in a year when customers experience emergency storms and spending was less than base funding, all underspend in service restoration would be allocated to the Resiliency Fund up to the cap of $30.7 million. Once the cap was reached, customers would be refunded as a bill credit. If the SRRF had a balance large enough to cover overages caused by catastrophic storms, the Company would not use ESA as SRRF dollars would be used first to supplement overages in restoration spending. Mr. Snider noted that the ESA could function independently from the SRRF.[3059] He went on to note the differences from the Service Restoration Cost Sharing Mechanism proposed by the Company in Case No. U-21585, which the Commission did not approve. Mr. Snider stated that the ESA would only be available for "extraordinary storms," defined to limit the eligible expenses for deferred accounting to

[3056] 3 Tr 2149.
[3057] 3 Tr 2149.
[3058] 3 Tr 2150.
[3059] 3 Tr 2151.

storms that cause the most damage to customers and restoration work for the Company and it gives the last word on deferred recovery to the Commission.[3060]

Staff witness Jessica Duell testified that Staff does not support the Company's request for a Service Restoration Resiliency Fund.[3061] Staff witness Duell stated that the requested mechanism should not be approved because: 1) Staff supports the full service restoration expense for the test year; 2) the Commission rejected other service restoration mechanisms in prior cases (U-20963, U-20697,U-21389, and U-21585); 3) customers will not see any benefit from this proposal due to the increase in storm restoration expenses in the past five years; 4) instead of putting unspent storm restoration expenses into a pool the Company could re-allocate the expenses to other distribution programs to further improve reliability; 5) the Company can request deferred accounting for any catastrophic storm that crosses their service territory in any year, as recently they did in MPSC Case No. U-21914.[3062]

Then Staff witness McMillan-Sepkoski testified that Staff did not agree with the Company's request to use deferred accounting to defer the costs of extraordinary storms.[3063] Ms. McMillan-Sepkoski provided two reasons in support of Staff's position:

First, after the extraordinary storm in March/April of 2025 in northern Michigan, the Company filed an *ex parte* case with the Commission, Case No. U-21914. This case was a request for approval of accounting authority to defer the operations and maintenance costs using a regulatory asset. This case was filed on April 23, 2025, and the Commission approved this action with stipulations in its Order dated June 12, 2025.

[3060] 3 Tr 2152.
[3061] 6 Tr 4399.
[3062] 6 Tr 4399.
[3063] 6 Tr 4516.

The Commission Order for the utilization of deferred accounting in Case No. U-21914 had rendered the final ruling merely seven (7) weeks, just Thirty-Seven (37) business days after the Company had filed, and Staff believes this is a reasonable amount of time for the Company to request and receive approval from the Commission to defer any extraordinary storm costs.

Second, there is no dollar amount tied to this request for deferral accounting. It is a "just in case" scenario. Staff does not believe that this would be best practices for the ALJ or the Commission to approve an open-ended request when there are other avenues that the Company can utilize.[3064]

Based on these reasons, Ms. McMillan-Sepkoski recommended disapproval of the request for Extraordinary Storm Accounting deferred accounting treatment for future service restoration costs.[3065]

Attorney General witness Coppola testified that the Service Restoration Resiliency Fund and the Extraordinary Storm Accounting procedure were complex proposals that required more research and study to assess how they would work in practice and their implication on cost recovery. Witness Coppola further testified that these programs were designed to reduce financial risk for the Company, which has considerable implications for the return on equity rate. A major reduction in risk and the likelihood of increased cost recovery of historical storm restoration costs would need to be reflected in a significant decrease in the approved ROE rate for the Company.[3066]

[3064] 6 Tr 4516-17.
[3065] 6 Tr 4517.
[3066] CONF 3 Tr 489-90.

Mr. Coppola stated that it was premature at this time to adopt the Company's proposals.[3067] Instead, he recommended the Commission not adopt the Company's proposal for the Service Restoration Resiliency Fund or the Extraordinary Storm Accounting procedure and instead open a generic docket to study proposals on storm restoration recovery mechanisms, not just for Consumers, but also to other electric utilities in Michigan.[3068] Mr. Coppola's recommendation to the Commission on this topic responded to proposals in Company witness Snider's testimony.[3069]

Citizens Utility Board (CUB) witness Richard J. Bunch also testified regarding the Service Restoration Resiliency Fund and the Extraordinary Storm Accounting proposals.[3070] He noted that the Company has put forth similar proposals in the past, which the Commission has addressed and rejected on multiple occasions. Mr. Bunch testified that in the Company's last electric rate case, U-21585, the Commission rejected the Company's Service Restoration Cost Sharing Mechanism (SRCSM), that would have allowed the Company to recover 50% of the excess service restoration costs above the authorized base amounts. In instances where the Company underspent on service restoration, the ratepayers would have received 50% of the difference as a refund. The Commission rejected this proposal, finding that it did not provide sufficient benefit for ratepayers to outweigh the additional risk it would place on them.[3071] Mr. Bunch testified that the Commission has rejected at least five such proposals over the past decade, consistently finding that they provide asymmetric benefits to the Company,

---

[3067] CONF 3 Tr 490.
[3068] 3 Tr 2418; CONF 3 Tr 490.
[3069] 3 Tr 2373.
[3070] 6 Tr 4066-71.
[3071] 6 Tr 4067.

shift the risks associated with restoration cost volatility to ratepayers, and reduce the Company's accountability for cost control.[3072]

Mr. Bunch noted that the SRRF and ESA were not significantly different from the previous proffers; specifically, they continued to skew the risks associated with volatile service restoration costs away from the Company towards the ratepayers and reduce Company incentives to implement cost efficiency in its service restoration.[3073] Mr. Bunch asserted that under SRRF, 100% of the underspent funds would be earmarked for future service restoration, effectively reducing the Company's risk in the future, with no upside to the ratepayers, until the fund reaches its cap of $30.7 million, when refunds would be issued.[3074] SRRF created asymmetric benefits for the Company and its shareholders at the expense of its ratepayers.[3075] Mr. Bunch testified that the ESA used a deferred accounting mechanism to recover excess restoration costs and was applicable only for costs related to 'extraordinary storms,' and their recovery would require the Company to demonstrate their prudence and reasonableness.[3076] He asserted that allowing deferred recovery for such events reduced the risk for the Company and its shareholders while increasing the ratepayers' exposure to restoration costs associated with large, extreme weather-related events.[3077]

Witness Bunch stated that the Company's performance did not justify these cost recovery mechanisms, as its overall reliability performance has been among the worst

---

[3072] 6 Tr 4067-68.
[3073] 6 Tr 4068.
[3074] 6 Tr 4068.
[3075] 6 Tr 4069.
[3076] 6 Tr 4069.
[3077] 6 Tr 4069.

in the nation.[3078] He asserted in the context of this poor reliability performance, Consumers Energy's continued proposals for cost recovery mechanisms that increase risks for ratepayers were unreasonable. He further noted the SRRF and the ESA make today's ratepayers financially responsible for storm damage substantially attributable to the Company's past distribution system maintenance practices.[3079] Mr. Bunch expressed additional concern about the lack of any prudence or oversight standards associated with the proposed SRRF. It allowed the Company to retain and later draw upon surplus ratepayer-funded dollars without any such review at the time of use. Once funds were deposited into SRRF, the Company could use them to cover future service restoration costs without demonstrating whether those costs were efficient, necessary, or reasonably incurred.[3080] Having shared his concerns regarding the proposed SRRF and ESA, Witness Bunch recommended that the Commission reject the Company's proposed Service Restoration Resiliency Fund (SRRF) and Extraordinary Storm Accounting (ESA) mechanisms.[3081]

Mr. Foster testified that the Service Restoration Resiliency Fund would allow the Company to record a regulatory liability when the actual projected test year expense was lower than the rate case authorized service restoration O&M. Staff witness Duell concisely laid out five reasons why the Commission should not adopt the Service Restoration Resiliency Fund: 1) Staff is supporting the full service restoration expense for the test year; 2) the Commission rejected other service restoration mechanisms in prior cases (U-20963, U-20697,U-21389, and U-21585); 3) Staff's position is that

[3078] 6 Tr 4069.
[3079] 6 Tr 4070.
[3080] 6 Tr 4070.
[3081] 6 Tr 4071.

customers will not see any benefit from this proposal due to the increase in storm restoration expenses in the past five years; 4) instead of putting unspent storm restoration expenses into a pool the Company could re-allocate the expenses to other distribution programs to further improve reliability; 5) the Company can request deferred accounting for any catastrophic storm that crosses their service territory in any year, as recently they did in MPSC Case No. U-21914.[3082]

Mr. Snider noted Staff's objection to the Company's SRRF based on Staff's support of the full-service restoration expense for the test year, skepticism that customers would see a benefit from this proposal, and a preference to direct underspent Service Restoration expenses into other distribution programs. He also noted CUB witness Bunch's recommendation to reject the SRRF because it was unlikely to benefit customers, and Attorney General witness Coppola's recommendation to reject the SRRF because the proposal was complex and required further study.[3083] Mr. Snider disagreed with the characterization that customers would not benefit from this proposal, as there was no extra cost to customers to implement the Resiliency Fund. Mr. Snider also disagreed that the SRRF was overly complex.[3084] He also asserted that the SRRF addressed Mr. Coppola's concern that the Company's proposed approach to projecting its service restoration expense did not "even out peaks and valleys in the annual expense."[3085]

Several of Staff's reasons were reiterated by CUB witness Bunch who pointed out that the Commission has rejected at least five such proposals over the past decade,

---

[3082] 6 Tr 4399.
[3083] 3 Tr 2170.
[3084] 3 Tr 2171.
[3085] 3 Tr 2171.

consistently finding that they provided asymmetric benefits to the Company, shift the risks associated with restoration cost volatility to ratepayers, and reduced the Company's accountability for cost control.[3086] Witness Bunch additionally asserted that under SRRF, 100% of the underspent funds would be earmarked for future service restoration, effectively reducing the Company's risk in the future, with no upside to the ratepayers, until the fund reaches its cap of $30.7 million, when refunds would be issued.[3087] SRRF created asymmetric benefits for the Company and its shareholders at the expense of its ratepayers.[3088]

Mr. Foster proposed the ESA accounting approval stating that it would allow for deferred accounting treatment for service restoration costs for severe storms once actual service restoration costs exceed amounts included in rates and any Service Restoration Resiliency Fund has been depleted. Staff witness McMillan-Sepkowski testified that Staff did not support the Company's request to use deferred accounting for the costs of extraordinary storms. She stated two reasons in support of Staff's recommended disapproval of the deferred accounting treatment. First, because the Commission has proven in Case No. U-21914 that it can timely approve an accounting authority to defer the operations and maintenance costs using a regulatory asset to defer any extraordinary storm costs. Second, there was no dollar amount tied to this request for deferral accounting. It was a "just in case" scenario. She asserted Staff did

[3086] 6 Tr 4067-68.
[3087] 6 Tr 4068.
[3088] 6 Tr 4069.

not believe that this would be a best practice for the Commission to approve an open-ended request when there were other avenues that the Company could utilize.[3089]

In rebuttal to Staff's criticism of the ESA, Company witness Snider testified that it had considered a cost threshold when developing this proposal and ultimately decided it was impractical. To ensure that the Company spent prudently without a specific cost threshold, he noted the Company proposed 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.[3090] In response to Staff's criticism of the ESA, Mr. Snider asserted that it established a standardized process completely visible to all interested parties in the rate making process, delivered efficiencies, and avoided the need for a separate ex-parte filing.[3091]

Mr. Bunch also recommended against approving the ESA, noting that allowing deferred recovery for such events reduces the risk for the Company and its shareholders while increasing the ratepayers' exposure to restoration costs associated with large, extreme weather-related events.[3092] Mr. Bunch pointed out that the Company's performance does not justify these cost recovery mechanisms, as its overall reliability performance has been among the worst in the nation.[3093] He asserted in the context of this poor reliability performance, Consumers Energy's continued proposals for cost recovery mechanisms that increased risks for ratepayers were unreasonable.

[3089] 6 Tr 4516-17.
[3090] 3 Tr 2172.
[3091] 3 Tr 2173.
[3092] 6 Tr 4069.
[3093] 6 Tr 4069.

In addition to the recommendations of Staff and CUB against adopting the proposed SRRF and ESA, the Attorney General also recommended the Commission not adopt the proposed SRRF and ESA. Witness Coppola testified that these programs were designed to reduce financial risk for the Company, which had considerable implications for the return on equity rate. A major reduction in risk and the likelihood of increased cost recovery of historical storm restoration costs would need to be reflected in a significant decrease in the approved ROE rate for the Company.[3094] Rather than adopt the Company's proposed accounting measures, Mr. Coppola recommended the Commission open a generic docket to study proposals on storm restoration recovery mechanisms.

In its brief, the Company relies on Mr. Snider's testimony to support the SRRF arguing that the Fund ensures that every customer dollar allocated to service restoration is either used to restore customers' power or is returned to customers as a credit.[3095] In response to objections, the Company argues that the fund comes at no additional cost to customers, is not overly complex, and is designed to operate in tandem with the re-baselined O&M expense.[3096]

The Company also relies on Mr. Snider's testimony to support the ESA, arguing that "[e]xtraordinary storms, which present challenging restoration conditions and cause significant damage to Company assets, are the main cause of increased service restoration spending and pose the largest risk to sustainable service restoration

[3094] CONF 3 Tr 489-90.
[3095] Consumers brief, p. 341.
[3096] Consumers brief, p. 342-43.

operations."[3097] The Company argues that storms are unpredictable and deferred accounting will help the Company ensure a reliable and resilient grid.[3098] The Company also notes that Liberty suggested deferred accounting as a possible solution to the Company's restoration budgeting problem and that other state regulatory commissions have approved deferred accounting mechanisms for their utilities.[3099] In response to Mr. Coppola and Mr. Bunch, the Company argues that the ESA is better than the ex-parte process because it creates a standardized mechanism with guardrails, establishes a higher threshold for deferred recovery, and gives the Commission the final say in a future rate case.[3100] The Company notes that either way the Company recovers its reasonable restoration costs from customers.

The Company urges the Commission to approve the Resiliency Fund together with its proposed service restoration expense and Extraordinary Storm Accounting proposal.[3101]

In its brief, Staff relies on the testimony of Staff witness Duell for its recommendation that the ALJ and Commission not approve the Resiliency Fund.[3102] After reiterating the testimony on the Resiliency Fund offered by the intervenors, the Attorney General and the Company, Staff's position remains that the Resiliency Fund should not be approved by the ALJ and Commission because: 1) Staff is supporting the full service restoration expense for the test year; 2) the Commission rejected other service restoration mechanisms in prior cases (U20963, U-20697,U-21389, and U-

[3097] Consumers brief, p. 344.
[3098] Consumers brief, p. 344.
[3099] Consumers brief, p. 344.
[3100] Consumers brief, p. 346.
[3101] Consumers brief, pp. 343, 347.
[3102] Staff brief, p. 195.

21585); 3) customers will not see any benefit from this proposal due to the increase in storm restoration expenses in the past five years; 4) instead of putting unspent storm restoration expenses into a pool the Company could re-allocate the expenses to other distribution programs to further improve reliability; 5) the Company can request deferred accounting for any catastrophic storm that crosses their service territory in any year, as recently they did in MPSC Case No. U-21914.[3103] Staff also argues that there is no need for the Commission to open a separate docket to discuss and review different service restoration proposals, as was recommended by the Attorney General.[3104]

Relying on the testimony of Staff witness McMillan-Sepkoski, Staff also recommends that the Company's request for the proposed Extraordinary Storm Accounting deferral for future storm restoration costs be denied as not in the best interest of ratepayers.[3105] Staff asserts that the Company has the option to file an ex-parte case to recover costs through deferred accounting, and also notes that the Attorney General considers it premature to adopt the ESA, while CUB argues it transfers the risk of the restoration costs from the Company and its shareholders to the ratepayers.[3106] For these reasons, Staff urges the ALJ and Commission to disallow the proposal by the Company for the Extraordinary Storm Accounting deferred recovery request.[3107]

In her brief, the Attorney General largely reiterates Mr. Coppola's testimony and argues that the Resiliency Fund and the ESA require more research and study to

---

[3103] Staff brief, pp. 196-8.
[3104] Staff brief, p. 198.
[3105] Staff brief, p. 184.
[3106] Staff brief, pp. 183-4.
[3107] Staff brief, p. 184.

assess how they would work in practice and their implication on cost recovery. Ultimately, the Attorney General states that the record does not establish the need for such a mechanism and recommends that the Commission reject this proposal.[3108]

In its brief, MNSC argues the Commission should reject Consumers' proposed Service Restoration Resiliency Fund (SRRF).[3109] MNSC argues that the SRRF is unlikely to deliver adequate, if any, benefits to the ratepayers. Additionally, it also appears premature and unnecessary for the Commission to open a separate docket to analyze the SRRF or similar frameworks without any historic underspending data from Consumers to study.[3110] Consumers has repeatedly overspent on service restoration in recent years. Consumers' actual restoration costs averaged $124.8 million annually, while the Company's budgets averaged just $48.5 million.[3111] Until Consumers demonstrates "sustained efficiency gains that offset the growing pressures from extreme weather," the Company's likelihood of underspending remains low. Even if Consumers does underspend in the test year, the proposed SRRF's $30.7 million cap diminishes customers' chances of reaping commensurate benefits. While the Service Restoration Cost Sharing Mechanism proposes to evenly divide any underspent amounts between Consumers and ratepayers, the SRRF creates "asymmetric benefits for the Company and its shareholders," affording "no upside to ratepayers" until the Company has reserved for itself millions of dollars.[3112]

[3108] Attorney General brief, p. 181.
[3109] MNSC brief, p. 54.
[3110] MNSC brief, p. 54.
[3111] MNSC brief, pp. 54-55.
[3112] MNSC brief, pp. 55-56.

MNSC also argues the Commission should reject the Company's proposed Extraordinary Storm Accounting (ESA) or, if the Commission finds merit in the ESA, the Commission should study it in a separate docket. MNSC asserts that the ESA proposal reveals that, in the face of growing extreme weather risks, Consumers expects its overspending pattern to continue.[3113] As proposed, the ESA would shield the Company and its stakeholders from restoration costs without providing any reciprocal benefits to ratepayers.[3114] Finally, MNSC asserts the proposed ESA would be redundant. As Commission Staff points out, Consumers can already recover extraordinary storm costs through ex-parte cases.[3115] As an alternative to rejecting the ESA, MNSC is willing to support the Attorney General's suggestion to further study ESA in a separate docket; however, MNSC avers the Company has not presented sufficient evidence to justify its proposal.[3116]

Reply briefs add nothing further on these issues.

Having reviewed the testimony and recommendations of the Company, Staff, the Attorney General, and MNSC/CUB, this PFD concurs with Staff and MNSC and recommends the Commission not adopt the SRRF or the ESA because adoption of these measures would be neither reasonable nor fair to Consumers' ratepayers. The measures are unnecessary, as demonstrated by the availability of the ex-parte option, and provide asymmetric benefits to the Company, shifting the risks associated with restoration cost volatility to ratepayers, and reducing the Company's accountability for

---

[3113] MNSC brief, p. 56.
[3114] MNSC brief, pp. 56-57.
[3115] MNSC brief, p. 58.
[3116] MNSC brief, p. 59-60.

cost control[3117] without providing any benefit to the ratepayers. This PFD also recommends the Commission not adopt the Attorney General's proposal to open a separate docket to further study this proposal.

4. Generation O&M Expense

Mr. Blumenstock supported Consumers' projected test year Generation O&M expense of $103,732,461, which is lower than the 2024 historical actual expense of $128,438,405.[3118] He explained that in addition to funding the daily operation and maintenance of Consumers' generating plants, the spending category includes several supporting internal organizations, such as Lean Organization and Enterprise Project Management.[3119] He asserted that the bridge and test year projections for "Base" expenses were determined by considering staffing levels and historical spending.[3120] He also noted that Base expenses, which are categorized as labor and non-labor, tend to increase at predictable rates.[3121] He testified further that adjusted expenses include "Environmental Operations," "Major Maintenance," and the "Retention and Separation" expenses for Karn and Campbell.[3122] He noted that total Generation O&M expenses have decreased by an annual average of 9% from 2024 through the projected test year reflecting changes in Consumers' mix of generation assets and major maintenance expenses, as well as cost recovery realignment and waste reduction measures.[3123]

[3117] 6 Tr 4067-68.
[3118] 6 Tr 3553-3554; Ex. A-43.
[3119] 6 Tr 3553.
[3120] 6 Tr 3555.
[3121] 6 Tr 3554-3555.
[3122] 6 Tr 3555.
[3123] 6 Tr 3555; Ex. A-43.

Mr. Blumenstock compared projected test year expenses to actual 2024 expenses for several generating facilities. He explained that Consumers is forecasting $14.829 million for the retired Karn Units 1 and 2, which is only 0.51% higher than the 2024 actual expense.[3124] He noted that the projected expense for Campbell Units 1, 2, and 3 is only $0.279 million, which is $41.061 million less than its 2024 actual expense, due to the cease of operations in May 2025.[3125] He testified that expenses for Covert, Ludington, and the River Hydros are projected to be higher in the test year then they were in 2024 primarily due to Major Maintenance costs.[3126] He added that Ludington Base expenses are also projected higher due to FERC assessments, license initiatives, and fish protection.[3127] He noted that while Consumers is planning to divest the River Hydros, they must still be operated and maintained. However, the Company is proposing a one-way tracker and will refund costs if the projected expenses are not required.[3128]

Mr. Blumenstock explained that Administration and Generation Commons expenses are projected to increase by $5.684 million because of a reorganization to Lean Organization, the filling of vacancies in Enterprise Project Management Organization, and due to reliability spending, among other reasons.[3129] He also asserted that Consumers' total projected Generation O&M expenses were reduced by waste reduction projects, and he noted two examples from Ludington and Covert.[3130]

[3124] 6 Tr 3558.
[3125] Id.
[3126] 6 Tr 3558-3560.
[3127] 6 Tr 3559.
[3128] 6 Tr 3560-3561.
[3129] 6 Tr 3561.
[3130] 6 Tr 3562.

Mr. Blumenstock described Environmental Operations, Major Maintenance, and Retention and Separation expenses in detail. He testified that Environmental Operations funds the installation of air quality compliance strategy (AQCS) equipment to facilitate compliance with state and federal air quality emission standards.[3131] He stated that Environmental Operations expenses are projected at $2.045 million, which is significantly lower than the 2024 historical expense of $8.539 million due to the retirement of the Campbell Units 1, 2, and 3.[3132]

He testified that Consumers is projecting test year Major Maintenance expenses of $32.982 million and noted that these expenses fluctuate year-to-year and by individual generating unit.[3133] He explained that the expenses are categorized as either "outage," requiring the removal of the affected unit from service, or "non outage," which do not require that the unit be removed from service.[3134] He detailed projects at Campbell, Karn Units 1-4, Covert, Zeeland, Jackson, Ludington, and the River Hydros.[3135] He also provided projected expenses for the "Admin and Other Major Maintenance" category and for the Classic 7 units at Cobb, Weadock, and Whiting.[3136] He explained that even though the Classic 7 units were retired in 2016, environmental regulations require the continued maintenance of on-site ash ponds.[3137]

Lastly, Mr. Blumenstock testified that Consumers projects spending $5.182 million in the 16-month projected bridge period for Retention and Separation expenses

---

[3131] 6 Tr 3562-3563.
[3132] 6 Tr 3563; Ex. A-43.
[3133] 6 Tr 3565-3566; Ex. A-43.
[3134] 6 Tr 3566-3568.
[3135] 6 Tr 3569-3577; Ex. A-43.
[3136] 6 Tr 3578; Ex. A-43.
[3137] Id.

related to the Campbell site.[3138] He testified that Consumers is not requesting O&M recovery of the $5.182 million because it has approval to defer the costs, and he noted that the Company is not projecting any test year expenses either.[3139] He described the retention and separation plans for Karn and Campbell in detail.[3140]

Staff witness Maio recommended the removal of $2.849 million from Consumers' projected test year Generation O&M expense which is the amount the Company projects for "Emergent Reliability Funding" within Base O&M.[3141] She testified that Staff's understanding, based on Consumers' discovery responses, is that the $2.849 million is an increase to the historical 2024 expense of $8.346 million, which she noted was inflated to reflect test year dollars.[3142] She also noted that $8.346 million is the highest amount from 2022 through 2024 and she opined that "there is no guarantee that the Company will spend an additional $2.849 million on Emergent Reliability Funding in the test year."[3143]

Mr. Bunch criticized Mr. Blumenstock for not providing more evidence or explanation for the stated 9% reduction in Consumers' average annual Generation O&M expenses since 2022. He testified that while Mr. Blumenstock noted that the reduction was primarily due to "a change in the mix of the Company's owned generating assets, including the movement of renewable energy resources to the Company's renewable energy plans," he left it unclear whether the decrease "reflects real operational

---

[3138] 6 Tr 3579; Ex. A-43.
[3139] Id.
[3140] 6 Tr 3579-3587.
[3141] 6 Tr 4469-4471.
[3142] Id.; Exs. S-8.5 through S-8.8.
[3143] 6 Tr 4471.

efficiency or a shift of costs from the rate case to the REP."[3144] Mr. Bunch noted, however, that the waste reduction projects described by Mr. Blumenstock "is perhaps the most relevant example presented by the Company of how it is identifying opportunities to reduce overall costs."[3145]

In rebuttal, Mr. Blumenstock provided the year-over-year details for all the O&M types by unit or plant and he explained that while his direct testimony did not include an all-inclusive plant-by-plant breakdown leading to the overall reduction of Generation O&M from the 2024 historical year to the projected test year, he did provide a discussion of the major drivers of the change.[3146] He noted generally that the projected test year O&M expense does not reflect a reduction due to the removal of renewable energy assets because while the projected test year does not include expenses associated with renewable energy projects, these expenses were also removed from the historical expense to provide an apples-to-apples comparison.[3147]

As for Staff's recommended disallowance to Emergent Reliability Funding, Mr. Blumenstock stated that, "[w]hile 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."[3148] He asserted that the O&M expense for the projected test year was developed

---

[3144] 6 Tr 4038-4039.
[3145] 6 Tr 4039.
[3146] 6 Tr 3625-3626; Ex. A-204.
[3147] 6 Tr 3626.
[3148] 6 Tr 3614.

based on the maintenance needs at each site or on specific units, rather than a simple escalation of historical year actual expenses.[3149]

Mr. Blumenstock also maintained that emergent reliability expenses have consistently increased, noting that they were $9,452 in 2022; $4.866 in 2023; $8.346 million in 2024; and $12.744 million from January through September 2025.[3150] He provided a breakdown of 2024 emergent reliability expenses by plant and used the Jackson Generating Station as an example to show that the historical plant expense is not included in the test year.[3151] He explained that $1,057 million of the $8.346 million emergent reliability expense in 2024 was allocated to the Jackson plant and included in the plant's total O&M expense of $11.616 million. He contrasted this with the projected test year O&M expense for Jackson of only $10.269 million, and opined, "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."[3152]

In its brief, Consumers elaborates upon Mr. Blumenstock's testimony and responds further to Staff's recommended disallowance. Consumers explains that Emergent Reliability Funding is used to address unforeseen and unpredictable reliability issues, such as equipment failures, urgent environmental compliance needs, or other reliability related corrective actions that are critical to maintaining safe and reliable generation operations.[3153] Consumers argues that Staff's disallowance is unsupported and the Company's requested funding level "is necessary to ensure that electric

---

[3149] 6 Tr 3614-3615.
[3150] 6 Tr 3615; Ex. A-201.
[3151] 6 Tr 3615-3616.
[3152] 6 Tr 3616.
[3153] Consumers initial brief, p. 351.

generation sites maintain high reliability standards and provide flexibility to address unplanned reliability events promptly, ensuring compliance, safety, and service reliability for customers."[3154]

In its brief, Staff points out that its determinations regarding Emergent Reliability Funding are based on Consumers' statements and discovery responses. Staff notes that Consumers' explained the difference between its projected generation O&M expense and the inflated 2024 actual expense shown in the "Other Adjustments" column in Exhibit A-43 as below:

> 1) the Other Adjustments simply reflect the difference between the test year amounts by subcategory that were calculated using the inflation rate and the test year amounts that were developed based upon the future maintenance needs of each unit and the supporting organizations, and 2) the Company's generating fleet is in a period of significant change with the retirement of coal units and the addition of Covert and renewables.[3155]

Staff also notes that Consumers stated that 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.[3156] Based on these explanations, Staff asserts that its position is that "the historical emergent reliability expense for each plant is part of the total plant maintenance and operation expense; therefore, the historical emergent reliability need/expense is included when the Company projects the future maintenance and operations need/expense for each plant."[3157] Moreover, Staff points out that Consumers also stated that "the Emergent Reliability expense is 1) budgeted annually, 2) it is necessary to fund emergent issues

---

[3154] Id., p. 353.
[3155] Staff initial brief, p. 118; Ex. S-8.8.
[3156] Staff initial brief, p. 118.
[3157] Id., p. 118-119.

that arise in the test year and 3) when spent, it is allocated to specific plants/units upon investment in the operations areas."[3158] Accordingly, Staff asserts that if the projected test year is developed based on the future maintenance and operations needs for each plant, the future emergent reliability need for each plant is included and considered in the development of the projected test year.[3159]

Staff also asserts that based on Consumers' statements related to the Campbell plant, it finds that Consumers' projected test year Generation O&M expense (excluding the projected Campbell O&M expense of $0.279 million) is 19%, or $16.359 million, higher than the historical expense of $87.094 million and 13%, or $11.667 million, higher than the historical inflated generation O&M expense of $91.786 million (again excluding Campbell).[3160]

Staff also argues that a breakdown of the 2024 emergent reliability expense and total O&M expense compared to the projected test year total O&M expense for a subset of plants (Covert, Jackson, Karn, Ludington, River Hydros, and Zeeland) shows that the total projected generation O&M expense of $80.429 million in the test year is 11%, or $7.933 million, greater than the total historical actual expense of $72.496 million, and 5% higher than the inflated actual expense.[3161] Staff contends that for these plants, the total projected generation O&M expense in the test year surpasses the total inflated historical/actuals generation O&M expense, in which the total historical emergent reliability expense of $8.346 million was included and inflated.[3162]

[3158] Id., p. 119.
[3159] Id.
[3160] Id., p. 119-120, citing Ex. S-8.5 and Ex. A-43.
[3161] Id., p. 120-121.
[3162] Id.

Based on the foregoing, Staff reiterates that Consumers' incremental Emergent Reliability Funding expense of $2,849,000 is in addition to the $8.346 million incorporated into the 2024 historical expense and there is no assurance this additional requested amount is needed or will be spent in the test year.[3163]

In reply, Consumers argues that Staff is essentially suggesting that the Company's evidence is not factually accurate.[3164] But, Consumers emphasizes that it *does not* forecast its test year O&M for generation by taking historical amounts and inflating them.[3165] Consumers contends that Staff is concluding that the historical Emergent Reliability expense amount must be included in the test year in addition to the $2.849 million merely because the total amount of O&M went up.[3166] Consumers provides the example of a car owner budgeting their expenses to argue that Staff's inference is illogical and unjustified:

> Say, for example, that a car owner budgeted $1,000 for a known need to get new tires in 2024 and $100 for any other unforeseen car maintenance costs (total: $1,100). But, during 2024, the owner needed a new battery for $150 (going slightly over budget). Then in 2026, the car owner budgeted $5,000 for a known need to replace the transmission and again $100 for any other unforeseen car maintenance costs that might occur in 2026 (total: $5,100). Staff's logic is that because the total cost in 2026 is higher than the cost in 2024, then the 2026 budget must include both the $100 of emergent car cost in 2026 and the $150 emergent car costs from 2024.[3167]

Consumers contends that Staff uses the same faulty logic when analyzing historical and projected costs for the subset of plants.[3168] Consumers argues that its

---

[3163] Id., p. 121.
[3164] Consumers reply brief, p. 15-17.
[3165] Id., p. 17.
[3166] Id.
[3167] Id.
[3168] Id., p. 17-18.

forecasted test year expense for Emergent Reliability is very conservative compared to its recent actual expense amounts and there is no double-inclusion of any expense amount from the historical year in the projected test year.[3169]

Staff's reply brief did not address the issue.

This PFD finds that it is reasonable for Staff to be concerned that Consumers' projected total Generation O&M includes double-counted Emergent Reliability expense based on Consumers' statements that its total Generation O&M spending includes the future maintenance needs of each plant. However, this PFD agrees with Consumers that Staff's logic is flawed. It does not follow that because the projected total Generation O&M expense for a subset of plants, which includes Emergent Reliability and all subcategories of spending, is higher than their historical total Generation O&M expense, which also includes all subcategories, then the subcategory of Emergent Reliability is double counted in the projected test year. Additionally, this PFD finds that an analysis of total Generation O&M costs, which exclude Campbell, does not lead to a different conclusion and notes that Campbell costs were $41.061 million higher in 2024 than for the projected for the test year. This PFD also finds that the Emergent Reliability spending of $12.744 million for January through September 2025 is notable in comparison to the projected amount of $2.849 million. Because this PFD finds that Consumers provided evidence that its projected spending on Emergent Reliability is reasonable and is not double counted in the test year, this PFD recommends the rejection of Staff's proposed $2,849,000 disallowance for Generation O&M. However, as noted above, this PFD finds that Staff's concerns are reasonable and therefore this

[3169] Id., p. 18.

PFD recommends that the Commission require Consumers to provide a detailed explanation of how the funding allocated to Emergent Reliability was spent in each historical year.

5. Customer Experience O&M Expense

Ms. Byrom presented O&M expenses relating to work within the Customer Experience and Operations (CX&O) organization, approximately $35 million for the test year consisting of $23.454 million for Customer Interactions and $11.505 million for Billing and Payment.[3170] In addition, The Company is projecting $533,000 in O&M "for customer investment to support the CX&O IT infrastructure."[3171]

According to Ms. Byrom, the CX&O O&M projection includes "$9 million of net recurring customer benefit to the electric business due to changes to the payment process" from implementation of a fee-based model for payments submitted through vendor payment channels, distributing the costs for high cost payment methods or fee based channels to residential and non-residential customers incurring the costs, rather than distributing the costs to customers using fee-free payment methods.[3172]

The Company's CX&O O&M expense was not contested; therefore, the amounts requested should be approved.

6. Corporate Services O&M Expense

Mr. Foster presented the Company's Corporate Services O&M expense category.[3173] Mr. Foster stated that Corporate Services includes those areas common to the administrative functions of a regulated corporation. These areas include

---

[3170] 3 Tr 967.4, 967.6. Consumers brief, 354.
[3171] 3 Tr 967.5-967.7.
[3172] 3 Tr 967.7.
[3173] 6 Tr 3354; Exhibit A-90.

Sustainability and External Affairs; Legal, Ethics, Regulatory and Risk Management; People and Culture ("P&C"), Learning and Development; Finance and Shared Services; General Activities; and Administration and other costs.[3174] Company witness Foster then provided a general overview of these areas.[3175] Notably, Sustainability and External Affairs group manages trade association dues and memberships[3176] and the Administrative and Other category of Corporate Services O&M expenses primarily represents costs for Edison Electric Institute dues, environmental minimum liability accruals, and intervenor funding.[3177]

Mr. Foster testified that Corporate Services expenses were allocated between the Company's electric and gas businesses based on the type of cost.[3178] Billing costs are allocated based on customer counts for the electric and gas business, P&C are allocated based on either employee counts or labor, general costs are allocated based on the Three Factor Allocation Method, with other costs being directly charged for identified activities allocated based on capital and O&M spending levels or special studies.[3179] Mr. Foster explained that the Three Factor Allocation Method uses the average of operating revenue, labor, property, plant, and investments to allocate costs between the electric and natural gas businesses.[3180] Mr. Foster testified that the 2024 actual O&M expenses were obtained from the Company's records, then specific line item changes were included as increases or decreases as appropriate to reflect

---

[3174] 6 Tr 3354.
[3175] 6 Tr 3354-56
[3176] 6 Tr 3355; Exhibit A-91.
[3177] 6 Tr 3356; Exhibit A-91.
[3178] 6 Tr 3356.
[3179] 6 Tr 3356-57.
[3180] 6 Tr 3357.

exclusions, remove one-time costs, reflect transfers of costs into or out of the Corporate Services area, or reflect significant ongoing changes in Corporate Services O&M expense.[3181] Mr. Foster then stated that the Adjusted Corporate Services O&M expense for 2024 was $37,543,000.[3182]

Mr. Foster testified that the assumed rate of inflation was based on the Consumer Price Index ("CPI") which considers factors specific to pricing of goods and services, such as the cost of food, energy, and housing. The CPI is 2.1% for 2025, 2.4% for 2026, and 2.4% for 2027. Consumers Energy uses these inflation rates to project Corporate Services O&M.[3183] In addition to the inflation increase, witness Foster testified to a $2,596,551 reduction to the projected test year for insurance distributions.[3184] Mr. Foster also explained that the adjustment for insurance distributions included the removal of ($6,369,342) for actual insurance distributions received in 2024, which was replaced with the five-year average for insurance distributions of ($8,965,893).[3185] He also noted that costs associated with restricted stock and the Employee Incentive Compensation Plan ("EICP") were not included in the 2024 actuals or projected Corporate Services O&M expense.[3186] Mr. Foster asserted that the O&M expense level for the projected test year was reasonable, pointing to the Company's 2023 electric A&G costs (excluding pension and benefits) rank as third

[3181] 6 Tr 3357; Exhibit A-91.
[3182] 6 Tr 3357; Exhibit A-91.
[3183] 6 Tr 3357.
[3184] 6 Tr 3358.
[3185] 6 Tr 3358.
[3186] 6 Tr 3358.

lowest by S&P Global Market Intelligence as a strong indicator of the Company's diligence in managing overhead costs to help keep rates affordable for customers.[3187]

Mr. Foster testified to how the Company determined the uncollectible accounts expense for the test year.[3188] He stated the Company projects the uncollectible accounts expense for the test year at $20,273,798.[3189] The projected test year uncollectible accounts expense was based on a three-year historical average Bad Debt Loss Ratio ("BDLR") of cash basis uncollectible accounts expense to electric service revenue for the years 2022 through 2024.[3190] This ratio was applied to the test year electric service revenue, plus surcharge revenue, to arrive at the sub-total of uncollectible accounts expense.[3191] Mr. Foster asserted that by using the test year revenues multiplied by the three-year average BDLR, the latest fuel and power cost projections are taken into account.[3192] He testified that this method most effectively captures the recent trends of the many factors that can impact uncollectible accounts expenses.[3193]

Mr. Foster then summarized the Company's total 2020 through 2024 actual electric injuries and damages expense and projected injuries and damages expenses through the 12 months ending April 30, 2027.[3194] Mr. Foster explained that electric injuries and damages included liabilities that arise in the normal course of Company business for various types of items such as compensation for damaged trees and crops;

[3187] 6 Tr 3358-59.
[3188] 6 Tr 3359.
[3189] 6 Tr 3359; Exhibit A-93.
[3190] 6 Tr 3359; Exhibit A-93.
[3191] 6 Tr 3359; Exhibit A-93.
[3192] 6 Tr 3360.
[3193] 6 Tr 3360.
[3194] 6 Tr 3360; Exhibit A-94.

restoration of driveways, lawns, and fences; and accidents and lawsuits (up to a $3,000,000 insurance deductible per occurrence). Further, workers' compensation costs were included in injuries and damages along with associated internal legal costs.[3195] Mr. Foster stated that the Company proposed that a total of $5,083,159 be included for the test year based on a five-year average of actual expenses for the years 2020 through 2024.[3196]

Sergio Cira-Reyes testified that the Company provided limited information about its corporate memberships – noting that Mr. Foster stated that "trade association dues and memberships" were included in the "Sustainability & External Affairs" area of Corporate Services and that Edison Electric Institute (EEI) was a primary cost associated with the "Administration and Other" area of Consumers' Corporate Services. Besides EEI, Witness Foster did not describe any other specific memberships or the costs associated with those memberships.[3197] Mr. Cira-Reyes testified on behalf of UCC that in response to discovery, the Company provided that it pays discretionary dues for six organizations, to include EEI, with an expense of $830,705, of which $770,775 was associated with EEI.[3198] The Company also gave generic descriptions of the benefits and functions of each trade association: "working with the Michigan legislature," "best practices," "continued economic growth," and "research."[3199]

Mr. Cira-Reyes testified that the Company had provided neither a sufficient description of the benefits and functions related to the $830,705 in trade membership

---

[3195] 6 Tr 3360-61.
[3196] 6 Tr 3361; Exhibit A-94.
[3197] 3 Tr 2355.
[3198] 3 Tr 2355-56.
[3199] 3 Tr 2356.

dues and fees that the Company sought to recover, nor a sufficient explanation for how these membership dues were accounted for in Corporate Services O&M expenses.[3200] Witness Cira-Reyes asserted that Consumers' lack of transparency and lack of sufficient explanation of each trade membership makes recovery unjustified. Mr. Cira-Reyes asserted that Consumers should be required demonstrate how recovered dues are directly supporting ratepayer benefits rather than expenses that have no benefit or undermine ratepayer interests.[3201] Mr. Cira-Reyes expressed appreciation that the Company elected to participate in EEI's Restore Power program; however, noted that the fee cap of $15,000 was less than two percent of the more than $770,775 Consumers pays in membership fees to EEI. He further asserted that participation in this voluntary program was not enough to justify recovery for the entirety of EEI's membership costs.[3202]

Mr. Cira-Reyes testified that the Company presents membership information with insufficient clarity and detail. He further asserted that 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.[3203] Mr. Cira-Reyes averred Consumers' requested recovery for all its corporate membership expenses was both unreasonable and unjustifiable, and the Company should be required to justify how its membership fees support

---

[3200] 3 Tr 2356.
[3201] 3 Tr 2356-57.
[3202] 3 Tr 2357.
[3203] 3 Tr 2358.

organizational activities to the benefit of its customers in its direct testimony and application.[3204]

Mr. Cira-Reyes noted that EEI and other organizations for which Consumers seeks to recover its membership dues from also engage in political advocacy.[3205] Mr. Cira-Reyes testified that in EEI's disclosures, the association engages with policymakers on member companies' behalf vis-à-vis "lobbying, advocacy, and regulatory proceedings." EEI estimated that at least 14.1% of membership dues would be used for lobbying alone in 2025.[3206] He asserted Consumers has offered no evidence that membership dues to these organizations provide tangible benefits for customers.[3207] Mr. Cira-Reyes then recited examples of activities taken by EEI that run counter to rate payer interests, which included: efforts to limit customer voices; opposition to solar energy and net metering; anti-clean energy and climate regulations; support for bailouts of uneconomic coal and nuclear plants; support for energy security plans that cost ratepayers millions; opposition to greater corporate transparency on emissions; and, aiding utilities in litigation against regulators and public interest groups.[3208] He then stated the Commission need not take sides on debates regarding climate and energy to see that it was evident that EEI's advocacy was centered on financial outcomes for utility shareholders instead of benefits for ratepayers.[3209]

Mr. Cira-Reyes further testified that the Company's funding of EEI through rates raised free speech concerns because Consumers is a local monopoly and customers

---

[3204] 3 Tr 2359.
[3205] 3 Tr 2359.
[3206] 3 Tr 2359.
[3207] 3 Tr 2360.
[3208] 3 Tr 2361-2365.
[3209] 3 Tr 2365.

must pay Consumers' rates or go without electricity.[3210] If the Company wanted to fund EEI's operations, its shareholders should pay for those fees, but customers should not be compelled to pay for advocacy counter to their interests without their direct approval.[3211] Mr. Cira-Reyes then listed the six states' public utility/services commissions that have disallowed recovery for memberships with EEI or similar trade organizations that engage in political advocacy.[3212]

Mr. Cira-Reyes concluded his testimony by recommending the Commission require Consumers to:

> (1) Provide detailed descriptions of each of their corporate memberships in their future rate applications,
>
> (2) Require Consumers to explain (1) the tangible benefits customers gain through each organization and (2) how membership fees are allocated toward programs that support ratepayer interests,
>
> (3) Disallow recovery for corporate memberships where there is no clear benefit to ratepayers and where a trade association directs a significant portion of membership dues to funding political advocacy, and,
>
> (4) Specifically disallow recovery for Consumers' entirety of EEI's $770,775 membership fees (except for the voluntary payments under the Restore Power program) because the Company has not established any tangible benefits derived from this corporate membership and EEI's demonstrated track record of undermining ratepayer interests as a lobbying organization.[3213]

In rebuttal, Mr. Foster addressed the recommendations made by UCC.[3214] Mr. Foster testified that the Company did not agree there was a lack of transparency

---

[3210] 3 Tr 2365-66.
[3211] 3 Tr 2366.
[3212] 3 Tr 2366-68.
[3213] 3 Tr 2369-70.
[3214] 6 Tr 3369.

surrounding its corporate memberships, pointing to Workpaper WP-PDD-18 of Company witness Patrick D. Daly in this instant case which disclosed 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.[3215]

Mr. Foster stated the Company agreed 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.[3216] Mr. Foster asserted that the benefits the Company and its customers receive from corporate memberships generally fit into one or more of the following broad categories: benchmarking, facilitate collaboration, research, and networking.[3217] The Company agreed that lobbying activity included in corporate membership dues should not be recovered from customers.[3218] The Company disallowed 16% of EEI dues and 27% of EEI Industry Issues dues from membership dues expense. These disallowed percentages were greater than the 14.1% of dues estimated by EEI to be spent on lobbying in 2025 and discussed in witness Cira-Reyes' direct testimony.[3219] In total, Mr. Foster asserted that the $830,705 included for recovery in this rate case was approximately 46% of the total membership dues costs, ensuring no expenses associated with public advocacy, lobbying, or solely benefiting shareholders are included for recovery in the rate case filing.[3220]

[3215] 6 Tr 3370.
[3216] 6 Tr 3370.
[3217] 6 Tr 3371-72.
[3218] 6 Tr 3372.
[3219] 6 Tr 3372.
[3220] 6 Tr 3374.

Mr. Foster testified that the Company's EEI membership provided a wide range of services and collaborative opportunities that directly support the Company's ability to deliver safe, reliable, and affordable service. These benefits extended 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; Cybersecurity and Technology Best Practices; Customer Support; Supplier Diversity and Networking; Regulatory Preparedness; Transportation Electrification; and Industry Expertise and Innovation.[3221] EEI's services were foundational to the Company's ability to operate efficiently, respond to emergencies, and plan. Mr. Foster further stated that EEI membership was a prudent investment that supported customer value, and the associated costs were reasonable and appropriately included in Corporate Services O&M.[3222] Witness Foster concluded his rebuttal by reiterating that Corporate Services O&M seeks recovery of $830,705 of corporate membership dues, which represented approximately 46% of the total membership dues costs.[3223]

Mr. Foster asserted that the benefits the Company and its customers received from corporate memberships generally fit into one or more of the following broad categories: benchmarking, facilitate collaboration, research, and networking;[3224] however, there was insufficient evidence in the record to discern how ratepayers may benefit from membership. The Workpaper already disclosed and excluded expenses related to lobbying, but it did not currently include a detailed description of the benefits

[3221] 6 Tr 3372-74.
[3222] 6 Tr 3374.
[3223] 6 Tr 3374.
[3224] 6 Tr 3371-72.

to customers from Consumers membership. The burden remained on Consumers to show the reasonableness of recovering membership expenses from ratepaying customers.

In its brief, the Company largely reiterates Mr. Foster's testimony arguing the reasonableness of the Company's Corporate Services expenses.[3225] The Company then went on to address UCC's recommendations.[3226] The Company expressed willingness to provide additional details related to corporate memberships in future rate applications as recommended by UCC and agreed that lobbying costs should not be recovered from customers.[3227] However, the Company disagreed with UCC's allegation that it offered no evidence in its initial case regarding its corporate memberships, pointing to its workpaper and discovery response.[3228] The Company then argues that the Commission should reject UCC's recommendation to disallow recovery of all dues paid to Edison Electric Institute ("EEI") because membership is a prudent investment that supports customer value, and the associated costs are reasonable and appropriately included in Corporate Services O&M and a portion of the expenses recommended for disallowance are already excluded.[3229]

In its brief, UCC argues that the Company has failed to provide adequate justification for recovering $830,705 in corporate membership dues and fees from ratepayers and states that the Commission should disallow recovery of the costs.[3230] UCC argues that an electric utility seeking a rate increase must include sufficient

---

[3225] Consumers brief, p. 356; Exhibit A-92.
[3226] Consumers brief, pp. 356-57.
[3227] Consumers brief, p. 356-57.
[3228] Consumers brief, p. 357.
[3229] Consumers brief, p. 357.
[3230] UCC brief, p. 121.

evidence in its initial application to demonstrate that its rates are "just and reasonable" and that Consumers failed to meet its burden by not providing sufficiently detailed explanations of how these memberships specifically benefit customers.[3231] UCC asserts that the Company barely mentioned corporate dues in its Application and the exhibit referenced in discovery did not include specific membership line items. In rebuttal the Company pointed intervenors to the Workpaper, WP-PDD-18; however, the Workpaper was never entered as an exhibit and the Workpaper figures do not match the requested recovery.[3232] UCC avers that Consumers failed to provide substantive evidence about its corporate memberships in its initial Application, in subsequent discovery, and in rebuttal testimony, and should therefore be denied recovery of costs.[3233] UCC argues that the Company's perfunctory benefit descriptions did not include sufficient tangible, specific benefits to ratepayers, or tangible examples of how activities result in benefits to ratepayers, which makes them so broad and non-specific that they provide an insufficient basis for the Commission to evaluate whether ratepayers receive tangible value from the memberships.[3234]

UCC asserts that the Company's request for recovery is deficient in two substantial respects. First, Consumers has failed to provide sufficiently detailed and tangible examples of how these dues and fees specifically benefit ratepayers.[3235] Accordingly, UCC requests that the Commission reject the Company's request to recover its corporate membership expenses and require Consumers to provide detailed

---

[3231] UCC brief, p. 121.
[3232] UCC brief, p. 123.
[3233] UCC brief, p. 125-26.
[3234] UCC brief, p. 126-27.
[3235] UCC brief, p. 127-30.

descriptions of each of their corporate memberships in future rate applications, which the Commission has already ordered another utility, DTE Electric, to do in Case No. U-20836.[3236]

Second, several of these memberships, particularly the Edison Electric Institute (EEI), fund advocacy activities that are demonstrably contrary to ratepayer interests which violates the U.S. Constitution's First Amendment's prohibition against compelled speech.[3237] UCC points to Consumers' status as a monopoly provider of essential services, being the exclusive electric utility service provider within its service territory, with customers effectively compelled to make payments to an entity (Consumers) that uses those payments to fund advocacy with which they may disagree since the Company does not provide ratepayers an "opt-out" option of discretionary corporate membership dues.[3238]

UCC also takes issue with Consumers additional 33 percent disallowance for certain trade associate dues derived by the Commission from testimony listing three general categories of benefits, one of which was explicitly acknowledged to exclusively benefit shareholders in MPSC Case No. U-15245.[3239] UCC argues that the utility still bears the burden of providing substantial evidence that the remaining costs benefit ratepayers through specific, transparent accounting that no requested funds for recovery can be or are being used for unconstitutional political advocacy or lobbying activities.[3240]

[3236] UCC brief, p. 131-32.
[3237] UCC brief, p. 7, 122.
[3238] UCC brief, p. 135.
[3239] UCC brief, p. 140.
[3240] UCC brief, p. 140.

Based on the arguments summarized above, UCC respectfully requests that the Commission: (1) Disallow the entire $830,705 in corporate membership dues sought by Consumers Energy. At a minimum, the Commission should disallow all costs associated with EEI membership, or limit EEI recovery to a maximum of $15,000 for the documented mutual assistance program. (2) Require itemized membership disclosures in future rate cases consistent with the disclosure standards established for DTE Electric in the orders in Case Nos. U-20836, U-21297, and U-21534, ensuring equal treatment of similarly situated utilities. (3) Establish a concrete standard barring recovery where trade associations dedicate significant resources to political advocacy, particularly where that advocacy is contrary to customer interests. This standard should apply consistently across all utilities under the Commission's jurisdiction, protecting all Michigan ratepayers from compelled subsidization of advocacy that serves shareholder, rather than customer, interests.[3241]

In its reply brief, the Company rebuts UCC's arguments for disallowing recovery of corporate membership dues and asserts that funds expended for political advocacy are excluded from the claimed expense.[3242]

While Mr. Foster testified that the Company's EEI membership provided a wide range of services and collaborative opportunities that directly support the Company's ability to deliver safe, reliable, and affordable service,[3243] and that EEI's services facilitate the Company's ability to operate efficiently, respond to emergencies, and plan

[3241] UCC brief, pp. 143-44.
[3242] Company reply brief, pp. 19-21.
[3243] 6 Tr 3373-74.

for the future,[3244] this PFD finds that while Consumers has provided some general evidence of benefits to ratepaying customers and has excluded obviously disallowed lobbying-related expenses from its recovery, the Company could do more to correlate membership fees directly with benefits to ratepayers and justify the expense. After reviewing testimony and arguments provided by the Company and UCC regarding corporate memberships and the Commission's past directives on corporate memberships, this PFD recommends the Commission direct the Company to turn its Working Paper into an Exhibit which is consistent with the disclosure standards established for DTE Electric in the orders in Case Nos. U-20836, U-21297, U-21534, and U-21860, ensuring equal treatment of similarly-situated utilities. Additionally, this PFD recommends the Commission direct Consumers to provide a detailed and itemized list of expenditures, with names of vendors and a detailed description of the nature of the expenses, of Consumers spending on electoral campaigns, advertising, marketing, lobbying, trade associations and 501(c)(3) and 501(c)(4) non-profits.

7. Information Technology O&M Expense

Ms. Baker testified that IT Operations O&M expense is used to provide the required level of operational support, reliability, and security for technology investments; maintenance for security facilities and systems to ensure system reliability, vulnerability assessments, and penetration tests; and fulfillment of all state and federal laws and regulations, perimeter protection, guards, card access, cameras, executive protection, and investigative services.[3245] She stated that operational work is required to keep

[3244] 6 Tr 3374.
[3245] 3 Tr 659.

information and physical assets protected from cyber threats and that physical security measures are essential in protecting the infrastructure that delivers electricity.[3246] Ms. Baker testified that the Company projected total IT Operations O&M expense of $66,659,000 ($55,297,000 for IT and $11,362,000 for Security) in the test year.[3247]

Ms. Baker testified that IT Investments O&M expense is used to fund the O&M portion of upgrade projects, asset refresh projects, and technology investments that are needed to provide new capabilities for internal business units, security operations, and customers.[3248] She stated that implementing current versions of technology enables the Company to operate secure and stable systems, remediate security vulnerabilities, keep customer and Company data secure, maintain vendor support, address defects that impair stability and functionality, and address version interdependencies and compatibility between systems.[3249] Ms. Baker testified that the Company projected total IT Investments O&M expense of $26,303,000 in the test year.[3250]

Staff and the Attorney General proposed adjustments of IT Investments O&M expenses related to various projects. Consistent with the treatment of capital expenditures for these projects (addressed previously), this PFD rejects the Attorney General's proposed disallowance of O&M expenses associated with the SAP S/4HANA Implementation project but recommends a total O&M disallowance of $1,028,000 for

---

[3246] 3 Tr 660-663.
[3247] 3 Tr 663-664; Exhibit A-17. Ms. Baker explained that, starting with this rate case, the Security Department is now part of the IT Department and is no longer represented by a separate witness. 3 Tr 646.
[3248] 3 Tr 670.
[3249] 3 Tr 671.
[3250] 3 Tr 672-673; Exhibit A-19.

two projects in the investment planning phase.[3251] This PFD also previously addressed, and rejected, Staff's proposed adjustments to the Digital Infrastructure Automation project and the ISIS Papyrus 2026 Upgrade project, both of which include O&M expenses. The remaining disputed issue is addressed immediately below.

Ms. Baker testified that the Company is requesting $50,579 in O&M expense for the Business Continuity – Program Management Tool project.[3252] She explained that the Company's current business continuity (BC) and disaster recovery (DR) program management tool (Riskonnect) does not offer the capabilities to advance program maturity and to foster a world class response to a business interruption.[3253] She added that the current tool limits automation opportunities and has gaps in how it handles template enhancements, which results in the need for manual workarounds in order to prevent losing critical data.[3254] According to Ms. Baker, the Business Continuity – Program Management Tool is critical for successful and effective BC, DR, and emergency management programs.[3255] The software tool will provide automation, enhance the Company's incident management processes, establish critical linkages between departments and essential functions they support, and will perform necessary analysis before, during, and after a disruption that allows for the efficient response to minimize downtime.[3256]

[3251] The Company's request to defer O&M expense related to the SAP S/4HANA Implementation project is addressed in the section of this PFD addressing accounting authority and requests for regulatory asset treatment.
[3252] 3 Tr 751.
[3253] 3 Tr 751.
[3254] 3 Tr 751.
[3255] 3 Tr 751.
[3256] 3 Tr 751.

Staff witness Zichi recommended a full disallowance of the expenses for this project.[3257] She testified that Staff learned through audit that the Company has been using Riskonnect since 2023 and that the Company is looking to implement a new system because Riskonnect does not meet Federal Emergency Management Agency (FEMA) and Incident Command System (ICS) standards adopted by the Company in 2013.[3258] The Company also responded that implementing a new system is not the only way to meet the Company's standards, but the current system does not have the capabilities to support the requirements.[3259] Ms. Zichi reasoned that if the standards were adopted in 2013, the current system that was put in place in 2023 would have adhered to these standards if it were deemed prudent by the Company.[3260] She stated that the Company failed to address this inconsistency and provide supporting information as to the prudency of adopting these standards now.[3261]

Ms. Zichi further testified that the Company has shifted this project from 2025 and 2026 to 2026 and 2027 across cases, noting that projected costs were included in Case No. U-21585 for 2025 and 2026, in Case No. U-21806 for 2026 only, and in this current case for 2026 and 2027.[3262] She also stated that the total company expected project O&M cost has continuously decreased across cases, starting in Case No. U-21490 through this case, with a total decrease of $431,460.[3263] And Ms. Zichi noted an audit response by the Company indicating that it has not selected a vendor or new

[3257] 6 Tr 4353.
[3258] 6 Tr 4353.
[3259] 6 Tr 4354, citing Exhibit S-14.1, p. 17.
[3260] 6 Tr 4354.
[3261] 6 Tr 4354.
[3262] 6 Tr 4354.
[3263] 6 Tr 4355.

software yet.[3264] Ms. Zichi concluded that given the constant decrease in projected costs, the change in implementation dates, the request for recovery of costs without having selected a vendor or new solution, and past decisions contradicting the current need for this project, the Company has not established that this project is prudent at this time.[3265]

In rebuttal, Ms. Baker disagreed with Staff's conclusion that the current system implemented in 2023 should have included ICS capabilities solely because the standards were adopted in 2013.[3266] She testified that the current tool supports BC and DR but does not include incident response capabilities aligned with FEMA and National Incident Management System (NIMS) ICS principles.[3267] She stated that incident management and BC/DR tools typically serve distinctly different functions; while BC/DR tools focus on maintaining and restoring business functions during and after disruptions, incident management tools address immediate response coordination and command during emergencies.[3268] Ms. Baker testified that the Company does not have an incident management tool in place.[3269] She explained that in 2023, the Company had a BC/DR tool that was at risk of technology obsolescence so the chosen solution was to replace unsupported BC/DR software, fulfilling those immediate BC/DR requirements but not incident management needs.[3270] Ms. Baker added that there is currently no single, cost-effective solution that comprehensively meets both BC/DR and FEMA/NIMS ICS-

---

[3264] 6 Tr 4355, citing Exhibit S-14.1, pp. 13-14.
[3265] 6 Tr 4355.
[3266] 3 Tr 775.
[3267] 3 Tr 775.
[3268] 3 Tr 775.
[3269] 3 Tr 775.
[3270] 3 Tr 775.

aligned incident management requirements, and the Company's decision to procure the BC/DR solution was appropriate given the Company's needs and capabilities available at the time.[3271]

In its initial brief, Staff argues that the Company did not believe it was a priority to meet the ICS standards adopted in 2013 when it implemented its current system in 2023, and the Company has not established why it is important to meet those standards now.[3272]

This PFD agrees with Staff that the Company has not shown the expenses for this project are necessary or otherwise prudent given the Company's failure to prioritize this project since adopting ICS standards in 2013, including when the Company implemented its current Riskonnect system in 2023 without adequately addressing its related incident management needs. In addition, this PFD questions whether the costs for this project will be incurred in the test year as planned, considering the change in implementation dates emphasized by Ms. Zichi and the fact that the Company has yet to select a vendor or a software solution. As a result, this PFD recommends disallowing $50,579 of O&M expense for the Business Continuity – Program Management Tool project.

8. Employee Benefits Expenses

Ms. Grob presented the Company's O&M costs to provide benefits to its employees and retirees, as reflected in Exhibit A-97. She testified that the Company projected a test-year O&M expense of ($45,156,000) for the Pension Plans[3273];

[3271] 3 Tr 775-776.
[3272] Staff brief, 125-126.
[3273] 3 Tr 1135; Exhibit A-97, p. 2, line 1.

$16,507,000 for the Defined Company Contribution Plan (DCCP)[3274]; $12,731,000 for the Employee Savings Plan (ESP)[3275]; $33,385,000 for active employee health care (including Health Savings Accounts (HSAs) and Health Care Flexible Spending Accounts (HCFSAs)), life insurance, and LTD[3276]; ($48,867,000) for retiree health care and life insurance[3277]; and $2,780,000 for Other Benefits, including expenses for the absence management program, the educational assistance program, and the employee assistance program.[3278] Because there are no disputes involving these expenses, they should be approved.

9. Incentive Compensation Expense

Consumers requests recovery of O&M expenses in the amount of $2,211,000 for its Employee Incentive Compensation Plan (EICP), representing approximately $467,000 for officer incentives and $1,744,000 for non-officer incentives.[3279] The Company asserts the amount requested for EICP is related to its operational goals and states that short-term incentive compensation linked to financial metrics is excluded from its request in this case.[3280]

Ms. Conrad provided support for the Company's EICP expenses and their inclusion in the projected test year expenses requested in this case. She testified about Consumers' compensation philosophy, the reasonableness of the Company's compensation levels, and the use of incentive compensation as an accepted corporate

---

[3274] 3 Tr 1142; Exhibit A-97, p. 1, line 2.
[3275] 3 Tr 1143; Exhibit A-97, p. 1, line 3.
[3276] 3 Tr 1146; Exhibit A-97, p. 1, line 4.
[3277] 3 Tr 1155; Exhibit A-97, p. 1, line 5.
[3278] 3 Tr 1156-1157; Exhibit A-97, p. 1, line 6.
[3279] Consumers brief, 365. Exhibit A-73.
[3280] Consumers brief, 365. 3 Tr 989-990.

practice to attract and retain employees.[3281] She stated that the EICP is a form of short-term incentive pay designed to reward performance over periods of approximately one year or less.[3282] She stated that both non-officer employees and officers participate in the short-term EICP.[3283] She sponsored Exhibit A-73, which provides a summary of actual and projected annual incentive O&M expenses. And she provided testimony to support the inclusion of approximately $2.211 million of O&M expenses related to the EICP in rate base.[3284]

Ms. Conrad testified that the Company uses various market surveys to structure non-officer compensation between base salary and incentive compensation, targeting overall compensation to within plus or minus 5% of the market median.[3285] Ms. Conrad testified that the incentive compensation is part of an employee's overall compensation and not an addition, such as a bonus.[3286] For officers, Ms. Conrad stated that the Compensation Committees of the Boards of Directors of Consumers Energy and CMS, with the advice of an independent third-party consultant, creates a compensation package that includes base salary, annual incentive compensation, and long-term incentive compensation targeted at the median of the competitive market.[3287] Ms. Conrad testified that in advising the Compensation Committees, the third-party consultant provides information about a Compensation Peer Group as well as information from Willis Towers Watson surveys of compensation in the public utility

---

[3281] 3 Tr 896.
[3282] Id.
[3283] 3 Tr 992.
[3284] 3 Tr 988, 1014. Exhibit A-73.
[3285] 3 Tr 989, 993-998. Exhibit A-72.
[3286] 3 Tr 989.
[3287] 3 Tr 989-990, 993. Ms. Conrad stated that the Company is not seeking recovery for the costs of long-term incentive compensation. 3 Tr 990, 993.

sector and general industry.[3288] She stated that the surveys are the confidential and proprietary work product of Willis Towers Watson, and Consumers is contractually prohibited from sharing this information, which is used in setting compensation for its top five officers.[3289] She further stated that to help evaluate the reasonableness of compensation for these officers, Consumers compiled in Exhibit A-74 non-confidential market data using compensation elements from the Compensation Peer Group's publicly filed proxy statements.[3290] Ms. Conrad stated that while this information does not perfectly represent the information used by the Compensation Committee, "that does not support the conclusion that it is inadequate to support the level of compensation for the Company's top five officers."[3291] She added that the Compensation Committee utilizes information beyond the proprietary benchmarking information in deciding how compensation will be set, and she claimed that the data in Exhibit A-74 allows for a valid comparison with the Compensation Peer Group.[3292]

Ms. Conrad testified that the EICP is based on six operational performance measures—Employee Safety, Culture Index, Customer Experience, Electric Reliability, Affordability, and Methane Emission Reduction—and one measure related to financial metrics.[3293] She stated that the performance metrics are the same for both non-officers and officers, but they are weighted differently and explained that 50% of non-officer incentive compensation is based on achievement of the operational performance

---

[3288] 3 Tr 1004-1006.
[3289] 3 Tr 1006-1007.
[3290] 3 Tr 1007.
[3291] 3 Tr 1007.
[3292] 3 Tr 1007-1008. Exhibit A-74.
[3293] 3 Tr 1009, 1014. Exhibit A-71.

measures, and the other 50% is based on the financial measure.[3294] For officers, 30% is based on operational measures and 70% is based on the financial measure.[3295] Ms. Conrad explained that while the Company uses both operational and financial goals in its EICP, it is not seeking recovery of $6.9 million linked to financial goals, including amounts associated with the Affordability operational measure, which the Company determined is financial in nature.[3296]

Ms. Conrad testified that the Company is seeking recovery of EICP expenses at 100% target levels.[3297] She stated that the threshold payout level is set so that it can typically be reached 80% to 90% of the time in a 10-year period, while maximum payout for exceptional performance will be achieved 10% to 20% of the time.[3298] Ms. Conrad stated that shareholders will bear the costs of incentive compensation paid above the 100% level.[3299] And she stated that for purposes of efficiency and improved service, the Company has combined operations as one organization, and therefore the EICP goals include gas and electric metrics.[3300]

Ms. Conrad testified that because the incentive plans are designed so that the total base salary plus incentive payments will be equivalent to the market-based compensation level, customers receive both qualitative and quantitative benefits from the EICP at no additional cost above market-based compensation.[3301] She further opined that the appropriate standard in evaluating whether the level of compensation is

---

[3294] 3 Tr 992, 1010.
[3295] Id.
[3296] 3 Tr 898-990, 1010.
[3297] 3 Tr 1012, 1014.
[3298] 3 Tr 1012.
[3299] 3 Tr 1017-0108.
[3300] 3 Tr 1013.
[3301] 3 Tr 1016.

reasonable is whether the overall level of compensation, including both base salary and incentive compensation, is reasonable.[3302]

Ms. Meschke testified that the EICP goals are developed in partnership with the Company's leadership team and are approved annually by the Board of Directors.[3303] She provided an explanation for each of the five operational goals for which the Company is requesting expense recovery (Employee Safety, Culture Index, Customer Experience Index, Electric Reliability, and Methane Emissions Reduction).[3304] She also testified about the annual process for setting the targets for the operational goals.[3305]

Ms. Meschke stated that the Company has evaluated the quantitative benefits associated with the Employee Safety, Electric Reliability, and Culture Index goals and has assessed the qualitative benefits associated with the other goals.[3306] She stated that the quantified benefits for electric customers total $30,654,930 in value, which far exceeds the total costs of the EICP allocated to electric customers.[3307] She explained that while both electric and natural gas are combined for purposes of the EICP, she used a 60% allocation (based on the total number of electric employees as a percentage of the total number of Consumers Energy employees) to calculate the annual savings for electric customers from the Employee Safety and Culture Index

---

[3302] 3 Tr 1017.
[3303] 3 Tr 1757-1758.
[3304] 3 Tr 1758-1762. Exhibit A-156
[3305] 3 Tr 1763.
[3306] 3 Tr 1763.
[3307] 3 Tr 1764-1766. Exhibits A-157 to A-159

goals.[3308] And she stated that improved Customer Experience is a benefit of achieving the EICP goals that is difficult to quantify but nonetheless quite real.[3309]

Based on Ms. McMillan-Sepkoski's testimony, Staff recommends the O&M expense for incentive compensation be reduced by $192,600.[3310] This disallowance reflects the EICP expense, in the projected test year, for the top five officers.[3311] Observing that the Company targets employee salaries to the market median, Ms. McMillan-Sepkoski testified that Staff requested the Company supply a comparison of compensation for the top five officers to the market median.[3312] Ms. McMillan-Sepkoski stated that the Company refused to provide the requested information claiming it is confidential and proprietary, and asserting it is contractually prohibited from sharing the information.[3313] Instead, Consumers offered Staff the opportunity to review report extracts of the Pay Governance report, with a list of conditions attached.[3314] Ms. McMillan-Sepkoski testified that Staff did not examine the extracts offered by the Company in this matter because the same information was viewed in a prior rate case. At that time Staff found no specific financial data was presented, merely information on how Pay Governance calculates the market data. [3315] The figures were anonymous as to each executive with no presentation of the financial "compensation data that Staff need to examine to make a valid comparison."[3316] Ms. McMillan-Sepkoski testified:

[3308] 3 Tr 1766. Ms. Meschke stated that the full customer benefit from the Electric Reliability goal impacts all electric customers. *Id*.
[3309] 3 Tr 1765.
[3310] Staff brief, 172. 6 Tr 4513. Exhibit A-71
[3311] Id.
[3312] 6 Tr 4513-4514.
[3313] 6 Tr 4514-4515. See Exhibit S-9.2.
[3314] 6 Tr 4514.
[3315] 6 Tr 4514-4515. Referencing MPSC Case No. U-21806.
[3316] 6 Tr 4515.

"Staff felt that until the Company can disclose the information that Staff needs to make a proper assessment, the usefulness of the reports is negligible."[3317] Staff is not able to determine if the proposed EICP compensation is reasonable without the requested information.[3318]

Based on Mr. Coppola's testimony, the Attorney General recommends that the Commission disallow the entire amount associated with EICP, $2.211 million for the projected test year, or in the alternative, the Attorney General argues that recovery should be limited to $1.459 million, an amount equal to 66% of the Company's targeted performance measures.[3319]

Mr. Coppola expressed concern that the performance measures "comingle electric and gas business measures" and use financial metrics.[3320] He also alleged the Company's EICP is heavily weighted toward financial measures, noting that 50% of non-officer compensation and 70% of officer compensation is related to financial goals.[3321] And Mr. Coppola asserted that because Consumers removed the requirements associated with achieving a minimum number of operating metrics, "even mediocre performance will be rewarded if only a single metric is achieved."[3322] Observing that both non-officers and officers have received large annual merit salary increase, he asserted that incentive compensation should reward exceptional performance.[3323]

[3317] Id.
[3318] 6 Tr 4513.
[3319] Attorney General brief, 194. 3 Tr 2591.
[3320] 3 Tr 2586.
[3321] 3 Tr 2585.
[3322] 3 Tr 2586.
[3323] 3 Tr 2590.

Mr. Coppola reviewed and challenged the quantitative analysis of customer benefits provided by Ms. Meschke and used to justify the inclusion of EICP expenses in rates.[3324] He asserted "the cost savings calculated by Ms. Meschke are inconsistent with recent trends in performance, aspirational, and not based on actual achievements."[3325] He testified that Exhibit A-157 shows the number of safety incidents is trending upwards from 107 incidents in 2022 to 124 in 2024.[3326] Mr. Coppola testified the Company's assumed reduction to 85 incidents in 2025 is "wishful thinking" and does not support the projected savings.[3327] He observed that Workers Compensation costs have decreased slightly, these costs have been erratic over the past few years and do not demonstrate a downward trend.[3328] Mr. Coppola confirmed SAIDI index results improved from 2020 to 2024, but argued that this improvement is "impacted by the Company's increased expenses for tree trimming and capital expenditures to improve the Company's infrastructure."[3329] And he disputed Ms. Meschke's asserted savings related to lower turnover. Using Exhibit A-159, Mr. Coppola stated employee turnover was 2.6% in 2024, higher than the 2.0% achieved in 2021 and testified the trend was not improving and does not support the purported cost savings.[3330] Noting that Ms. Meschke testified Consumers Energy's turnover rate is lower than other utilities, Mr.

[3324] 3 Tr 2587-2589.
[3325] 3 Tr 2589.
[3326] 3 Tr 2587. Exhibit A-157.
[3327] 3 Tr 2587.
[3328] Id.
[3329] 3 Tr 2588. See Exhibit A-158.
[3330] 3 Tr 2588. See Exhibit A-159.

Coppola testified the metric at issue involves the Company's actual experience, not a comparison.[3331]

Mr. Coppola testified that the EICP expenses of $2.211 million presumes the Company will achieve target performance for all goals at 100%. Observing the Company has not historically achieved 100%, he compared the Company's targeted operating measures and the actual performance achieved from 2020 to 2024 and determined the "average achievement rate" is 66%.[3332] He calculated an EICP payout equal to 66% of the total EICP expenses requested by the Company to be $1,459,000; a reduction of $752,000.[3333]

Mr. Coppola maintained no EICP should be included in rates. But noting that the Commission has approved incentive compensation in prior cases, he asserted the Commission should approve no more than $1,459,000 in O&M expenses for EICP.[3334]

In rebuttal Ms. Conrad began by addressing Mr. Coppola's criticisms and recommendations. She disputed Mr. Coppola's contention that the overall program is too heavily weighted toward financial measures, emphasizing that the Company is not including expenses for financial measures in its rate request.[3335] Ms. Conrad also disputed the assertion that EICP provides rewards for mediocre performance noting employees must earn the incentive each year.[3336] She asserted use of individual goals with minimum, targets, and maximum goals with payouts based on level of achievement is common practice, and testified that structuring the payout to consider performance of

---

[3331] 3 Tr 2588.
[3332] 3 Tr 2589-2590.
[3333] 3 Tr 2591.
[3334] Id.
[3335] 3 Tr 1025.
[3336] Id.

each goal individually ensures that employees have an independent motivation to achieve each goal.[3337] She again stated that the target levels of 100% are not excessive and incentive compensation paid above that amount is absorbed by shareholders.[3338]

In response to Mr. Coppola's concern related to the comingling of electric and gas performance measures, Ms. Conrad contended that the Company has combined operations and structured performance incentive goals to benefit both the gas and electric branches. She testified: "For that reason, the incentive plan contains both gas and electric measures."[3339] Ms. Conrad testified the Company used the inflation factor approved by the Commission to refute Mr. Coppola's assertion that salary increases have been above the rate of inflation.[3340] And Ms. Conrad testified that Mr. Coppola's conclusion that the EICP does not benefit customers is erroneous.[3341] She asserted that Consumers Energy's compensation plan motivates and focuses better employee performance.[3342] Ms. Conrad also disputed Mr. Coppola's claim that the Company had an average achievement rate of 66% over the last five years. She provided a table showing the average payout was actually 105% for operational goals.[3343] She maintained that the overall compensation levels, including EICP, is reasonable, and she argued that Mr. Coppola did not justify his proposed disallowance, asserting should be rejected.[3344]

[3337] 3 Tr 1025-1026.
[3338] 3 Tr 1026.
[3339] 3 Tr 1027.
[3340] 3 Tr 1027-1028.
[3341] 3 Tr 1028.
[3342] Id.
[3343] 3 Tr 1029.
[3344] 3 Tr 1028.

In response to Ms. McMillan-Sepkoski's testimony, Ms. Conrad asserted the Commission should reject Staff's proposed disallowance of $192,600 in costs related to the EICP for the Company's top five officers.[3345] She again stated that officer compensation is determined by the Compensation Committee of the Boards of Directors in consultation with an independent third-party, Pay Governance, and targets the market median or 50th percentile of a Compensation Peer Group.[3346] Ms. Conrad testified that the market median information requested by Staff is confidential, proprietary, and commercially sensitive data belonging to Willis Towers Watson, and she asserted that the company is prohibited from sharing the information.[3347] She testified Pay Governance provides the company with access to the proprietary compensation data collected in Willis Tower Watson's annual survey, produced for use only by database participants.[3348] Pay Governance has consent to use the information but not to disseminate it.[3349] Ms. Conrad again testified, in attempt to be helpful without providing the confidential information, the Company compiled non-confidential market information.[3350] Ms. Conrad claimed the data is "sufficiently consistent with the proprietary data that it does allow Staff to see a valid comparison . . . ."[3351] However, she acknowledged this market data "does not perfectly represent the information that the Company used to benchmark and assist the Compensation Committee to determine

---

[3345] 3 Tr 1032.
[3346] 3 Tr 1029.
[3347] 3 Tr 1030. See Exhibit S-9.2.
[3348] 3 Tr 1030.
[3349] 3 Tr 1030.
[3350] 3 Tr 1031.
[3351] Id.

compensation for Consumers Energy's top five officers."[3352] Then she asserted the report contained the same data shared with the Compensation Committee to determine appropriate officer compensation.[3353] Ms. Conrad maintained the Company supported this EICP expense, and testified that Staff's recommendation to exclude this expense for the top five officers is not appropriate.[3354]

In its brief, Consumers contends it has supported recovery of the requested EICP expense in the amount of $2,211,000 and provides a lengthy review of Ms. Conrad's and Ms. Meschke's direct testimonies to explain the EICP and its benefits. The Company concludes that the EICP is reasonable and argues that compensation without the incentive compensation would constitute below market pay, resulting in the a less qualified workforce.[3355] After reviewing Ms. Meschke's testimony, Consumers maintains that quantification of EICP benefits establishes the operational metrics provide value to customers in excess of costs.[3356] The Company also reiterates Ms. Conrad's rebuttal testimony addressing the proposed disallowances of Staff and the Attorney General.[3357]

Consumers Energy argues the Commission should reject Staff's recommended disallowance in the amount of $192,600 for incentive compensation attributable to the top five Company officers.[3358] The Company argues it does not possess, and is unable to supply, the information requested by Staff.[3359] However, the Company argues it supplied Staff with the opportunity to see "an alternative set of data using publicly

---

[3352] Id.
[3353] 3 Tr 1032.
[3354] Id.
[3355] Consumers brief, 367. 3 Tr 991.
[3356] Consumers brief, 371.
[3357] Consumers brief, 374-384.
[3358] Consumers brief, 374.
[3359] Consumers brief, 374-376.

available information" and argues this is the exact data used by the Board of Directors to determine compensation for the top five officers.[3360] The Company admits the data is less current, but asserts compensation for the top officers does not change radically.[3361]

In response to the Attorney General's proposed disallowance, the Company reiterates some of Ms. Meschke's testimony. The Company argues the EICP is part of a reasonable compensation package for its employees and asserts Mr. Coppola's analysis of the benefits provided to customers by the EICP program is flawed. [3362] The Company specifically disputes his arguments related to SAIDI, Workers Compensation, and employee turnover, arguing these metrics support the requested EIPC expense.[3363] And Consumers Energy disputes Mr. Coppola's assertion that the EICP goals are too heavily weighted to financial measures, by repeating that it is not seeking recovery of EICP expenses attributable to financial objectives.[3364] The Company refutes the assertion that a change to individual banding for the EICP metrics, rather than a system with many different goals, results in rewarding mediocre performance, by restating Ms. Conrads assertion that the system promotes independent motivation to achieve each of the goals.[3365] The Company argues the new system is more appropriate for ensuring that employees are not rewarded for failure.[3366]

In response to Mr. Coppola's expressed concern about the comingling of gas and electric metrics, the Company argues it has combined gas and electric operations and

---

[3360] Consumers brief, 377.
[3361] Consumers brief, 377-378.
[3362] Consumers brief, 379.
[3363] Consumers brief, 379-382.
[3364] Consumers brief, 382.
[3365] Consumers brief, 383.
[3366] Id.

therefore "its EICP plan contains both gas and electric measures."[3367] The Company again contends that appropriate costs are allocated to electric customers and inclusion of gas related metrics are "of no consequence to electric customers."[3368] And in response to Mr. Coppola's assertion that the Company has only achieved an average of 66% of its targeted level of performance, Consumers Energy argues Ms. Conrad established the actual EICP payouts averaged 105% over the past five years.[3369] The Company argues Mr. Coppola's reasoning that the EICP expenses should be reduced to 66% of the requested amount is not justified.[3370]

Staff, in its brief, argues the EICP expenses for the top five officers of the Company has not been substantiated, and based on the testimony of Ms. McMillan-Sepkoski, Staff recommends the Commission disallow $192,600 of the proposed EICP expense for the test year.[3371] Staff requested supporting information for the compensation of the top five officers but the Company refused to provide it.[3372] Staff confirm that Consumers Energy offered to allow a review of report extracts under some conditions. Staff did review these report extracts for MPSC Case No. U-21806 and found they did not present financial compensation data and were anonymous to each executive.[3373] Staff contends the Company failed to provide the necessary information for a proper analysis of this projected expense.[3374] Staff notes that the Commission has

---

[3367] Consumers brief, 384. 3 Tr 1013.
[3368] Consumers brief, 384.
[3369] Consumers brief, 384. 3 Tr 1028-1029.
[3370] Consumers brief, 384-385
[3371] Staff brief, 127-128.
[3372] Staff brief, 127. See Exhibit S-9.2.
[3373] Staff brief, 128.
[3374] Id.

previously held "[it] expects a more thorough presentation of compensation levels and metrics for the company's employee compensation plans."[3375]

Staff acknowledges the Attorney General's proposed disallowance but maintains a disallowance of $192,600 is appropriate. Staff recommends the Commission approve an EICP expense in the test year of $2,018,400.[3376]

The Attorney General provided a review of Mr. Coppola's testimony in her initial brief. Base on that testimony, the Attorney General argues that all EICP expenses should be disallowed.[3377] In the alternative, if the Commission approves EICP expenses, the Attorney General argues the Commission should only approve $1,459,000 for the potential achievement of 66% of the targeted performance, rather than the 100% level proposed by the company, with a resulting disallowance of approximately $752,000.[3378]

The Attorney General argues that the standards for recovery for EICP expenses, articulated in the Commission's order in Case No. U-14347 have not been met, and she contends the Company failed to show benefits commensurate with program costs.[3379]

Based on Mr. Coppola's testimony, the Attorney General argues the Company failed to quantify the alleged customer benefits of its EICP.[3380] The Attorney General contends the Company's analysis does not account for other factors that could influence performance, such as training, discipline, promotion, or legal requirements.[3381] The

---

[3375] July 31, 2017 order, Case No. U-18124, pp 87-88.
[3376] Staff brief, 129.
[3377] Attorney General brief, 194
[3378] Id.
[3379] Attorney General brief, 185-186. December 22, 205 order, Case No. U-14347, p 34.
[3380] Attorney General brief, 188.
[3381] Id.

Attorney General states some of the metrics have worsened in recent years and do not support the projected cost savings, and she contends that there is an extremely low threshold for payout of EICP based on operational goals.[3382] The Attorney General also maintains, based on Mr. Coppola's testimony, that the Company achieved an average target rated of 66% for the performance measures in the last five years.[3383] She points out that average payout at 105% as calculated by Ms. Conrad, "included performance measures achieved above the target level to offset measures that were not achieve at all or were achieve below target level."[3384]

This PFD finds that Staff's proposed disallowance should be adopted, and recommends the Commission reject $192,600 in EICP expenses for the top five officers. Staff's arguments are more persuasive and consistent with Commission precedent. The same issue was addressed in Case No. U-21389 and the expense was disallowed. In that case, the ALJ ruled:

> [I]t was the company's choice to rely on supporting information that it had chosen to keep confidential. Had the company wanted to rely only on the additional "public" information that Ms. Conrad subsequently provided in discovery, it should have said so in its direct filing.[3385]

The Commission agreed with the ALJ and found: "[I]t was the company's choice to rely on information in a database owned and controlled by a third party."[3386] And the Commission found:

[3382] Attorney General brief, 189-192.
[3383] Attorney General brief, 192-193. 3 Tr 2589-2590.
[3384] Attorney General brief, 193. 3 Tr 1028-1029.
[3385] December 21, 2023 PFD, Case No. U-21389, p 428. See also March 1, 2024 order, Case No. U-21389, pp 193-194 (cited with approval).
[3386] March 1, 2024 order, Case No. U-21389, p 195.

> [I]t is possible to share with the Staff confidential information related to EICP expense through a protective order without disclosing confidential or proprietary information or methods used by the third party.[3387]

The Commission ruled the Company did not sustain its burden of proof noting that "Staff was unable to determine that the company's proposed expense is reasonable."[3388]

In U-21585 the Company made substantially the same arguments about the sufficiency of evidence presented to support inclusion of the EICP expense for the Company's top five officers.[3389] The ALJ cited the Commission findings in U-21389 and ruled "the Commission's directive to the company is incontrovertible - in order to sustain the burden of proof the company must be able to supply the underlying data to establish expense amounts are reasonable and prudent."[3390] The Commission again agreed with the ALJ citing the reasoning in the PFD with approval.[3391]

And in U-21806 an identical issue was addressed. The ALJ cited the Commission's order in U-21389 and found no compelling reason to deviate from the Commission's previous findings.[3392] Again the Commission agreed finding "the Staff remain stymied in its attempt to make the market comparisons that are relevant to Consumers' compensation projections."[3393]

In this case the Company again relied on data, which it claims is confidential, to calculate EICP for the top five officers, and will not supply the information it relied on to support this calculation. Again, the evidence presented is not materially different than

---

[3387] Id.
[3388] March 1, 2024 order, Case No. U-21389, p 196.
[3389] March 21, 2025 order, Case No. U-21585, pp 345-346, 348-350.
[3390] January 27, 2025 PFD, Case No. U-21585, p 469.
[3391] March 21, 2025 order, Case No. U-21585, pp 349-350.
[3392] August 14, 2025 PFD, Case No. U-21806, p 397.
[3393] September 30, 2025 order, Case No. U-21806, pp 237-238.

the evidence presented in prior cases. As in prior cases, the Company provided additional public information, offered in lieu of the actual data, claiming it was similar. The Commission has repeatedly rejected the Company's argument, finding refusal to provide information to support this expense prevents appropriate review. This PFD notes that the Company asserts it provide less current financial data to Staff claiming it is the same as provided by third parties. However, if the data is actually the same, the Company did not explain why it relied on confidential data which it is unable to supply to the Commission.

Accordingly, this PFD recommends the Commission again find the Company did not support its proposed EICP expense for the top five officers and disallow the EICP expense in the amount of $192,600.

The Attorney General has recommended the Commission disallow the entire EICP amount requested by the Company in prior cases, making very similar arguments as presented in this matter. The Commission rejected these arguments, finding the EICP to be part of an overall compensation package that is reasonable and prudent and should be allowed, except for the amount associated with the top five officers addressed above.[3394] This PFD does not find the Attorney General's recommendation to disallow recovery of all EICP expenses to be persuasive given the above analysis and Commission precedent. And this PFD finds the Attorney General did not establish that an amount equal to 66% of the Company's projected total EICP expense is reasonable and prudent. Accordingly, the PFD recommends the Commission reject the Attorney

[3394] See example September 30, 2025 order, Case No. U-21806, p 237 and March 21, 2025 order, Case No. U-21585, p 354.

General's proposal to disallow the entire EICP expense amount, and her alternative recommendation that $752,000 be disallowed based on the likely achievement of 66% of its targeted performance goals.

The parties in this case did not make specific arguments related to the inclusion of the operational performance metric for the reduction of methane emissions, however the issue was noted. This PFD finds reduction of methane emission is not a proper EICP goal for electric employees. Again, the Commission addressed this same issue in U-21389, finding that "it is not appropriate for the electric division of Consumers to recover costs for a metric whose target may only be achieved by employees in the gas division of the company." [3395] The Commission found this metric should not be included in the EICP for electric employees.[3396] This PFD recommends the Commission reaffirm its finding that the reduction of methane emissions metric is not an appropriate operational goal for electric employees and should not be included for the purposes of EICP calculations.

10. Inflation Rates

a. Rates

Mr. Daly testified that Consumers' revenue deficiency presentation uses inflation factors of 2.10% for 2025, 2.40% for 2026, and 2.40% for 2027, as forecasted by S&P Global Market Intelligence and reported in the November 2024 edition of U.S Economic

[3395] March 1, 2024 order, Case No. U-21389, p 196.
[3396] Id.

Outlook.[3397] Ms. Conrad testified that Consumers uses the same inflation factors to adjust both labor and non-labor expenses.[3398]

Mr. Coppola applied Consumers' proposed inflation rates in his forecasts for capital expenditures and used a prorated rate of 2.9% for the 16-month bridge period.[3399] For O&M expenses, Mr. Coppola testified that he did not reduce Consumers' inflation adjustments for employee salary/merit increases, as he has in prior cases, since he agreed with the Company's inflation rates.[3400]

The parties' respective briefs reassert support for Consumers' inflation factors.

As there is no apparent opposition to Consumers' proposal to apply inflation factors of 2.10% for 2025, 2.40% for 2026, and 2.40% for 2027, these rates are adopted, subject to relevant productivity offsets as appropriate as discussed below.

b. Productivity Offsets to Inflation

Ms. Myers provided testimony responding to the Commission's directive in Case No. U-21585 that Consumers present more detailed evidence to demonstrate that it is offsetting inflation by productivity gains.[3401] She explained that while Consumers is committed to transparency and rigor in its economic analyses, it faces significant challenges in isolating and quantifying the precise impact of productivity gains as an offset to inflationary pressures. She continued that productivity improvements do not always manifest as dollar reductions but in indirect or diffuse ways, such as through process efficiencies, technological integration, or workforce optimization, that are not

[3397] 3 Tr 1050-1051; Ex. A-13, Sch. C-5.1.
[3398] 3 Tr 999, citing Case No. U-2093, Order, Dec. 22, 2021, p. 244-251.
[3399] 3 Tr 2420.
[3400] 3 Tr 2569.
[3401] 3 Tr 1833.

easily captured in traditional financial metrics or short-term reporting frameworks.[3402] She testified that these complexities make it difficult to present granular, standalone evidence that definitively attributes cost containment or margin stability to productivity gains alone and while Consumers can point to broader trends and strategic initiatives aimed at enhancing efficiency, it cannot provide detailed, itemized documentation required to show productivity gains by line item in witness exhibits. However, she emphasized that this should not be interpreted as a lack of effort or effectiveness by Consumers in managing inflationary impacts through productivity.[3403] She also asserted that developing projected costs for many programs is more complex than simply applying an inflation factor to historical costs. She maintained that the Company's witnesses support the costs they are sponsoring and the methodology used to develop those costs.[3404] She provided examples from witnesses, such as Ms. Stewart, who explained that clearing more frequently reduces unit costs to maintain the LVD system and that Forestry contains costs through contractually limited inflation increases.[3405] Ms. Myers also provided examples of how costs are developed from Ms. Baker on IT Operations O&M, Ms. Byrom on Customer Experience & Operations, Mr. Blumenstock on Generation O&M, Mr. Snider on service restoration costs, Mr. Foster on Adjusted Corporate Services O&M, and Mr. Guinn on facilities maintenance expense and real estate expense.[3406]

[3402] Id.
[3403] Id.
[3404] 3 Tr 1833-1834.
[3405] 3 Tr 1834.
[3406] 3 Tr 1834-1835.

CUB witness Bunch testified that Consumers has failed to present more detailed evidence to demonstrate that it is offsetting inflation by productivity as it was directed to do in Case No. U-21585.[3407] As a result, he recommended an overall reduction of $59.5 million from Consumers' proposed O&M costs based on limiting the Company to productivity-adjusted inflation (PAI) increases from historical 2024 levels, excepting the Line Clearing surge.[3408] He also recommended that in future rate cases, the Commission constrain Consumers to PAI increases in O&M, as well as capital expenditures, and require it to justify any departures from these limits in terms of changes in sales, legal, or performance requirements.[3409]

Mr. Bunch contended that the Commission's review process should act as a proxy for market forces and Consumers should be required to demonstrate that it is achieving productivity gains similar to those of companies operating in competitive markets.[3410] He explained that competitive companies cannot raise prices in response to inflation without losing market share.[3411] As a result, he testified, these companies manage inflation in other ways, such as by harvesting operational efficiencies, implementing alternative procurement strategies, renegotiating contracts, and managing workforce turnover.[3412] He maintained that while Consumers and other utilities do not face competitive pressure to keep prices low, they still have the same arsenal of responses to manage inflationary cost increases.[3413]

[3407] 3 Tr 4039.
[3408] 6 Tr 4047-4048.
[3409] 6 Tr 4040.
[3410] Id.
[3411] 6 Tr 4026.
[3412] 6 Tr 4026-4027.
[3413] 6 Tr 4028.

He opined that the examples provided by Ms. Myers' fail to demonstrate how Consumers is harvesting productivity improvements and lack details on how the Company plans to manage labor rates, contractor costs, or postage rates and become more cost-efficient.[3414] He maintained that while the examples provide more detail than Consumers provided in Case No. U-21585, the details are not relevant or responsive to the Commission's previous order.[3415] He asserted that, "[w]hile it may be a challenging exercise to implement, it is Consumers' burden to present evidence showing how it is incorporating cost containment and productivity into its budgeting process rather than simply assuring the Commission that it is doing so."[3416] Mr. Bunch testified that if Consumers were delivering more electricity with greater reliability at a faster rate than its revenue requirement were growing, that would be a high-level indicator of productivity gains. He stated instead that, "the Company proposes to deliver a little bit more electricity slightly more reliably by increasing capital spending almost 63%, a tremendous decline in capital productivity, and O&M spending by more than 21%."[3417]

Mr. Bunch contended further that Consumers applies inflation inconsistently.[3418] He testified that Mr. Daly presented the O&M programs where inflation factors were used, but his presentation did not always align with the actual inflation assumptions used by sponsoring witnesses, including Ms. Grob (DCCP and Savings Plan costs) and Ms. Byrom (Customer Experience and Operations O&M).[3419] He also maintained that there are examples where the impact of inflation is embedded in cost projections

---

[3414] 6 Tr 4037-4039.
[3415] 6 Tr 4040.
[3416] 3 Tr 4036.
[3417] 6 Tr 4040.
[3418] 6 Tr 4031.
[3419] 6 Tr 4032-4033.

without being identified as an explicit factor, such as Forestry Operations.[3420] He opined that Consumers' treatment of inflation in cost projections is not comprehensive, consistent, or clear and he added that the Company does not provide a breakdown of inflation adjustments for capitalized costs.[3421]

Mr. Bunch asserted that Consumers' test-year spending is projected to increase by 21.4% for O&M expenses and 62.8% for capital expenditures from 2024 historical actuals, with labor costs increasing by 32.5% and non-labor costs increasing by 52.5%.[3422] He testified that the bulk of the increase in costs is contained in the "Other Adjustments" column of the Company's exhibits. He added that Consumers' projected compounded inflation rate during the same period is 5.39%.[3423]

He maintained that if Consumers responded to cost pressures as effectively as companies in competitive markets, then it should be able to recover reasonable costs with rates that increase at a productivity-adjusted inflation (PAI) rate where inflation is offset by labor and capital productivity while mitigating the impacts of increasing costs on rates.[3424] Mr. Bunch opined that the Commission should hold Consumers' expenditures related to ongoing, or baseline, activities to productivity-adjusted growth no greater than the PAI factor, but allowing for case-by-case adjustments for changes in sales, legal or performance requirements or other adjustments.[3425] He asserted that given Consumers' inconsistent presentation, the application of productivity offsets should not be limited to the line-items where the Company is explicitly using an inflation

---

[3420] 6 Tr 4033-4034.
[3421] 6 Tr 4034.
[3422] 6 Tr 4035-4036, Table 1.
[3423] 6 Tr 4036.
[3424] 6 Tr 4041.
[3425] Id.

factor to arrive at projected test-year estimates, but the PAI factor should be applied consistently across all programs to both O&M costs and capital expenditures.[3426]

Mr. Bunch recommended that the Commission start by applying productivity factors (for labor and non-labor) to whatever inflation rates are approved in this case to project all O&M expenditures and disallow excess costs unless they are driven by sales growth or specific performance or legal requirements, such as the costs associated with the Line Clearing surge.[3427] And he opined that going forward, in the same way that the Commission allows Consumers to propose inflation factors, it should allow the Company to propose the productivity factors that best correspond to its cost structures.[3428] He noted that he is not making any recommendation for capital expenditures in this case in the interest of gradualism and to allow Consumers to become more conversant in the methodology.[3429]

He recommended that the Commission limit O&M labor costs to 2024 historical levels plus compounded Labor PAI, calculated using the Bureau of Labor Statistics (BLS) labor productivity figures for Michigan's private, non-farm sector.[3430] He maintained that the compounded annual change in labor productivity in Michigan from 2014-2024 was 1.34%, which results in a Labor PAI rate of 0.76%, 1.06%, and 1.06% in 2025, 2026, and 2027, respectively.[3431] For non-labor O&M costs, he recommended that the Commission limit projected costs to 2024 historical levels plus non-labor Total Factor-PAI, calculated using the BLS Total Factor Productivity (TFP), which compares

---

[3426] 6 Tr 4042.
[3427] 6 Tr 4043-4044.
[3428] 6 Tr 4043.
[3429] 6 Tr 4044.
[3430] 6 Tr 4045.
[3431] 6 Tr 4045, Table 2.

the amount of goods and services produced to the amount of combined inputs used for goods and services for the US private, non-farm business sector.[3432] He testified that the compounded annual change in TFP from 2014-2024 was 0.81%, and applying this average factor to Consumers' projected inflation factors derives a non-labor Total Factor-PAI rate of 1.29%, 1.59%, and 1.59% in 2025, 2026, and 2027, respectively.[3433] He presented his program-specific recommendations for test-year O&M expenditures and recommended that the Commission use the PAI-adjusted cost approach to limit growth in O&M spending by completely disallowing $59.5 million in proposed O&M costs.[3434] For future cases, he recommended that the Commission direct Consumers to present both O&M and capital test-year cost baseline projections calculated as historical cost adjusted for PAI.[3435]

In rebuttal, Ms. Myers responded that Consumers' costs are fully supported even if, as Mr. Bunch claims, its witnesses' presentations are inconsistent.[3436] As for the Company's cost increases, she maintained that there are many reasons other than inflation that costs increase, and these other costs are, and should be, included in the Other Adjustments column of Consumers' exhibits.[3437]

She rejected Mr. Bunch's PAI methodology and disputed his contention that regulated utilities have the same tools to manage inflation as companies operating in competitive markets. She testified that unlike unregulated companies, a regulated utility has an obligation to serve its customers and must do so according to safety, service

---

[3432] 6 Tr 4045.
[3433] 6 Tr 4046, Table 3.
[3434] 6 Tr 4046-4047, Table 4.
[3435] 6 Tr 4048.
[3436] 3 Tr 1850.
[3437] Id.

quality, and reliability standards.[3438] She stated that Consumers "already operates around the clock to meet customer demand and cannot compromise safety or reliability by overextending equipment or deferring necessary investment."[3439] She testified further that Mr. Bunch's implication that Consumers does not manage costs is false and she emphasized that, "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."[3440] She testified that Consumers strives to implement and incorporate productivity gains into its costs to keep customer rates affordable and continues to work to improve its processes for identifying and highlighting productivity gains in its rate cases. However, she stressed that the standard for cost recovery is whether costs are reasonable and prudent, not whether productivity gains have been incorporated into costs or whether costs increase by more than inflation.[3441]

Ms. Myers testified that Consumers' proposed distribution capital investments are designed to improve reliability by reducing outage frequency and duration and modernizing grid operations, which will enable productivity gains by lowering operating expenses over time.[3442] She noted, for example, that automation and grid modernization initiatives reduce manual labor and emergency response costs, directly impacting O&M and yielding long-term value.[3443] She opined that the Commission should not interpret increased capital and O&M spending as a failure to achieve productivity, but recognize

---

[3438] 3 Tr 1851.
[3439] Id.
[3440] 3 Tr 1852-1853.
[3441] 3 Tr 1853.
[3442] 3 Tr 1852.
[3443] Id.

it as foundational to delivering sustained improvements in reliability, safety, and operational efficiency.[3444]

Ms. Myers recommended that Mr. Bunch's proposal to adjust all O&M expenses, except for forestry, to historical expenses adjusted for PAI should be rejected. She maintained that it would significantly impact Consumers' ability to achieve reliability goals as outlined in the Reliability Roadmap.[3445] She referred to Mr. Kelly's testimony supporting reliability investments and stated that increases in non-forestry reliability O&M are driven by expanded inspection and monitoring of system equipment including in four sub-programs: LVD Lines Reliability, HVD Lines Reliability, LVD Substations Reliability, and HVD Substations Reliability.[3446] She asserted that the Reliability Roadmap identified that historic spending levels in these sub-programs were insufficient to complete needed maintenance work, maintain adequate inspections, and address maintenance backlogs.[3447] She contended that to continue this important reliability work, the remaining O&M categories would have to be reduced by more than 13%, which is unreasonable and would most likely leave Consumers no choice but to pull back on some of the necessary distribution work.[3448]

Ms. Myers testified that there should never be a standard that simply caps expense levels at amounts below inflation. She asserted that "[t]his would be a major and dangerous deviation from the Commission's review of expense levels through the

[3444] 3 Tr 1852-1853.
[3445] 3 Tr 1854.
[3446] Id.
[3447] 3 Tr 1854-1855.
[3448] Id.

lens of whether the expenses are reasonable and prudent and in support of safe and reliable delivery of electricity."[3449]

Mr. Kelly also rebutted Mr. Bunch's testimony, suggesting that his proposal "would simply cause deterioration on the system to rapidly accelerate" and that his recommendation to "hold other reliability investments at PAI-adjusted current levels" is vague.[3450]

Consumers' brief largely tracks Ms. Myers' testimony and argues that Mr. Bunch's proposed blanket reduction in O&M costs ignores the extensive support provided by its witnesses explaining how O&M costs are projected and the work that will be performed.[3451] Consumers emphasizes that it does not have a single formulaic methodology for projecting O&M and the projected costs for each program are determined by the most reasonable and prudent method.[3452] Further, Consumers argues that Mr. Bunch's assertion that unregulated companies do not pass on inflationary costs as part of price increases is unsupported and unrealistic.[3453] Consumers emphasizes that 93% of Mr. Bunch's proposed reduction is related to electric distribution O&M expense, which is directly tied to the Reliability Roadmap and supports increased capital investments through maintenance and operation of grid infrastructure, engineering and design work needed to execute projects, restoration of service to customers following interruptions, expanding inspection and monitoring of system equipment, addressing maintenance backlogs, and enhancing public safety and

---

[3449] 3 Tr 1856.
[3450] 3 Tr 1614.
[3451] Consumers initial brief, p. 387.
[3452] Id., p. 388.
[3453] Id., p. 389.

supporting system reliability.[3454] Consumers opposes Mr. Bunch's recommendation requiring PAI-related reductions, arguing that it is "risk-filled" and Consumers must be afforded sufficient funding to provide safe and reliable service to customers.[3455]

In briefing, MNSC elaborates upon Mr. Bunch's testimony, noting that Consumers' rebuttal misses the point of his productivity analysis, which is the overall decreasing affordability of Consumers' electricity, particularly for its residential customers, while its rate increases outpace even inflation increases.[3456] MNSC counters Consumers' rebuttal argument that regulated utilities have obligations that unregulated companies do not, stating that unregulated companies also have to adhere to safety, service quality, and reliability expectations and ensure safe conditions for employees. MNSC asserts that "[a]rguing that the utility should not have to show the regulator that it is operating efficiently because it is a regulated utility is misguided and circular – it is precisely because it is a regulated utility that the potential exists for inefficiencies and cost bloat."[3457]

MNSC goes on to argue that Consumers' suggestion that increased spending is "foundational" to achieve operational efficiency makes no sense because the foundation of "operational efficiency" is not increased spending, it is either spending less to produce consistent operations, or it is the same spending to produce more outputs.[3458]

[3454] Id., p. 390.
[3455] Id.
[3456] MNSC initial brief, p. 68.
[3457] Id., p. 70.
[3458] Id., p. 70-71.

Moreover, argues MNSC, Consumers has been unable to identify improved reliability or productivity gains resulting from its recent spending increases.[3459]

MNSC contends that Consumers' suggestion that the test for spending should be whether individual program spending is reasonable and prudent is flawed for three reasons. MNSC argues that: 1) the Company has the most complete understanding of its cost structures and is in the best position to rebalance spending and the Commission should keep them accountable to overall spending standards; 2) without a portfolio-level benchmark, such as PAI, the individual program review relieves Consumers of its managerial responsibility to balance costs prudently and to parse each individual expenditure; and 3) the Commission's attempt to obtain program-level productivity gains has been largely unsuccessful, given the record in this case.[3460]

MNSC addresses Consumers' assertion that 93% of the recommended reduction would be to electric distribution O&M. MNSC contends that Mr. Bunch's recommended disallowance is an across-the-board reduction, including IT and employee-related programs, and some disallowances are offset by positive PAI adjustments for generation costs.[3461] MNSC adds that the Company's plans to invest increasing levels of O&M on the distribution system is a reason to find productivity benefits in other program areas to ensure the overall cost of delivering safe, reliable service remains reasonable and prudent for customers.[3462]

Finally, MNSC argues that that the PAI method is not a spending cap, it is necessary because Consumers has failed to effectively incorporate productivity gains in

---

[3459] Id., p. 71.
[3460] Id.
[3461] Id., p. 72.
[3462] Id.

its costs, and therefore has not demonstrated that its proposed O&M expenses are reasonable and prudent.[3463] MNSC further contends that its recommendation is directly responsive to the Commission's directive in U-21585 and instead of following the Commission's directive, Consumers argued that it should not have to demonstrate productivity offsets and it revealed a fundamental misunderstanding that higher spending is evidence of productivity.[3464]

This PFD agrees with MNSC that Consumers did not provide more detailed evidence demonstrating that it is offsetting inflation by productivity as directed to by the Commission in U-21585. Consumers' claims that it is too difficult a task are unavailing and tend to prove MNSC's point that without regulatory pressure Consumers and other regulated utilities do not have incentive to manage inflation.

As for MNSC's recommendation to reduce O&M spending by $59.5 million in this case, this PFD declines to adopt it. This PFD agrees with Consumers that spending should be considered in the context of the supporting evidence provided by Company witnesses for individual programs and sub-programs. This is also consistent with Commission precedent which disfavors blanket reductions and prefers to evaluate spending on a more detailed, program-by-program or project-by-project basis.[3465] However, this PFD finds that MNSC's argument to use productivity-adjusted inflation, or PAI rates to adjust future costs is reasonable and supported by the evidence and would mitigate the impact of inflation on future costs. Moreover, this PFD notes that Consumers did not propose alternative productivity offsets than those proposed by

---

[3463] Id.
[3464] Id.
[3465] *See* Case No. U-21806, Order, Sept. 30, 2025, p. 11-12.

MNSC. Therefore, this PFD recommends that in those specific programs and sub-programs where Consumers has increased its projected test year costs by its proposed inflation factors (2.10% for 2025, 2.40% for 2026, and 2.40% for 2027) that instead of using Consumers' inflation rates, MNSC's proposed non-labor Total Factor-PAI rate of 1.29% for 2025 and 1.59% for 2026 and 2027 and a Labor PAI rate of 0.76% for 2025 and 1.06% for 2026 and 2027 be used.

Turning to MNSC's proposal for future rate cases, this PFD finds it reasonable that productivity offsets be consistently incorporated into rate cases but declines to adopt MNSC's recommendation that capital expenditures and O&M expenses be limited to PAI-adjusted historical levels. Nonetheless, consistent with the above discussion, for future rate cases, this PFD recommends that Consumers propose productivity adjustment factors, in addition to inflation rates, and that in those specific programs, with both O&M expenses and capital expenditures, where inflation is applied to future costs, that the PAI be applied.

D. Depreciation and Amortization Expense

Mr. Daly testified that Consumers used the Commission-approved book depreciation rates, projected capital expenditures, and assumed plant retirements to determine the depreciation expense adjustment necessary to arrive at an appropriate level of book depreciation expense for the projected test year.[3466]

Mr. Witt presented Staff's proposed depreciation expense based on Staff's proposed adjustments to historical and projected capital expenditures.[3467]

[3466] 3 Tr 1057; Ex. A-13, Sch. C-1.1.
[3467] 4 Tr 4604.

In its brief, Consumers recommends approval of the depreciation and amortization expense of $811,743,000.[3468]

Please see the PFD appendices, which will be available on the docket before February 6, 2026, for the PFD's final adjustments and recommended depreciation and amortization expense.

E. Taxes

Brian J. VanBlarcum serves as the Tax Director with the Company's Corporate Tax Department where his responsibilities include administration of the Company's real and personal property taxes.[3469] Mr. VanBlarcum identified the Property Tax Rate for the test year and explained how the rate was derived. He also supported the amount of test year excess deferred federal income taxes being returned to electric customers resulting from the Tax Cuts and Jobs Act of 2017 ("TCJA") and the Commission's September 26, 2019 Order in the Company's Calculation C proceeding, Case No. U-20309.[3470]

Mr. VanBlarcum testified that the Property Tax Rate for the test year was 0.013349387, which was calculated using the Company's prorated Electric Property Tax Expense, divided by the total of the 2026 Estimated Year-End Plant-in-Service, one-half of the 2026 Estimated Construction Work in-Progress.[3471]

The 2026 taxes paid by Consumers of $281.9 million on behalf of the electric portion of the business represented the estimated property taxes to be paid in 2026. The Electric Property Taxes on 2026 Plant Investment was $33.6 million which will be

[3468] Consumers initial brief, p. 391, App. C1.
[3469] 3 Tr 2259.
[3470] 3 Tr 2261.
[3471] 3 Tr 2263; Exhibit A-180.

included in the 2027 property tax liability calculated by taking the capital additions, less retirements, times the first year State Tax Commission multiplier table value to recognize a depreciation allowance, which was then multiplied by the statutory reduction of 50% of true cash value to get the assessed value, then multiplied by Consumers Energy's composite millage rate of 49.7863 to obtain the estimated tax amount. The 2027 Fossil Plant Valuation Tax Reduction was decreased $0.1 million reflecting a reduction in property taxes associated with the D.E. Karn Plant (Units 3-4), which was the result of successful negotiations with the local unit of government over the taxable value of the Company's fossil fuel-fired electric generating facilities.[3472]

Electric Property Taxes on Real Property Taxable Value Increases was a $1.2 million increase for the Real Property Taxable Value related to the Michigan Constitution of 1963, Article IX, Section 3, allowing local assessors to raise real property taxable values by the lesser of 5% or the Consumer Price Index ("CPI"). For 2027, the Company's property tax model assumed a CPI rate of 2.4%.[3473] The result of including the Electric Property Taxes on 2026 Plant Investment, 2027 Fossil Plant Valuation Tax Reduction, and Electric Property Taxes on Real Property Taxable Value Increase on the estimated 2027 property tax amount paid by the electric business was an estimated 2027 property tax amount to be paid for the electric business of $316.6 million.[3474] Pollution control equipment and computer software such as SAP are exempt under MCL 324.5904(1) and MCL 211.9d, the estimate of 2027 property tax to be paid did not

[3472] 3 Tr 2263; Exhibit A-180.
[3473] 3 Tr 2264; Exhibit A-180.
[3474] 3 Tr 2264; Exhibit A-180.

include property taxes associated with these items.[3475] Company expenses property taxes based on the fiscal year of the taxing authorities, 50.0% of the 2026 estimated electric property tax payments for Consumers Energy was added to the 2027 estimated electric payments since that amount would be expensed in 2027, while subtracting 50.0% of the 2027 estimated electric payments that would be expensed in 2028, arriving at a total 2027 electric property tax expense of $299.3 million.[3476]

For the test year, Mr. VanBlarcum testified that property tax expense was prorated for the period of May 1, 2026, through April 30, 2027, using a monthly budgeted sales percentage applied to the 2026 and 2027 estimated annual property tax expense amounts. The result of factoring property tax expense monthly for the test period was a prorated Electric Property Tax Expense of $280.5 million. The prorated Electric Property Tax Expense for the test year was divided by the 2026 Estimated Year-End Plant-in-Service plus one-half of 2026 Estimated Construction Work-in-Progress to arrive at a property tax rate of 0.013349387.[3477] Mr. VanBlarcum testified that the Company was not currently involved in property tax litigation.[3478]

Mr. VanBlarcum next addressed the Commission's September 26, 2019 Order in the Company's Calculation C case, which authorized the amount and period under which the Company would refund to electric customers $1,174,181,000 of excess deferred federal income taxes resulting from the TCJA lowering the corporate income tax rate from 35% to 21%. As part of the settlement terms in Case No. U-21224, the Commission approved an adjustment to reduce this amount by $4,168,278 to correct an

[3475] 3 Tr 2263; Exhibit A-180.
[3476] 3 Tr 2263-64; Exhibit A-180.
[3477] 3 Tr 2264; Exhibit A-180.
[3478] 3 Tr 2264.

overstatement of the TCJA remeasurement and authorized three different amortization periods.[3479] He also stated the Company proposed to refund an additional $7,907,000 of excess deferred taxes ($10,604,000 of regulatory liability after gross-up for taxes) in this case. This amount represented the Company's regulatory liability recorded as of year-end 2022 which was calculated as the difference between the actual amount of excess deferred taxes for the year and the estimated amount included in rates.[3480] Mr. VanBlarcum also provided a calculation of the test year excess deferred federal income taxes included in this case based on the periods approved by the Commission in Case No. U-20309. Overall, the Company reduced Federal Income Tax Expense for the test year by $40.434 million to reflect the amortization periods and amounts discussed above.[3481] The amounts included in this case were estimated as the Commission's September 26, 2019 Order in Case No. U-20309 required an annual reconciliation of the actual amount of excess deferred federal income tax in a given year and the estimated amount included in rates.[3482]

Mr. Coppola recommended an adjustment to the Company's proposed capital expenditures which lowered the amount of property tax expense the Company would incur during the projected test year by $4.0 million. Therefore, Mr. Coppola recommended reducing the Company's property tax expense by that amount for the projected test year.[3483]

[3479] 3 Tr 2264-65; Exhibit A-181.
[3480] 3 Tr 2265; Exhibit A-181.
[3481] 3 Tr 2266; Exhibits A-181, A-13.
[3482] 3 Tr 2266.
[3483] 3 Tr 2506; Exhibit AG-21.

In its brief, the Company addresses property tax noting that while no party challenged the method that Mr. VanBlarcum used to calculate electric property tax expense, Staff presented a different total property tax amount of $278.253 million.[3484] The Company does not oppose the method Staff used to calculate the property tax expense, but the Company disagrees with several of Staff's expense assumptions.[3485] Consumers requests that the Commission adopt a property tax amount of $279,986,000, explaining that the difference between its filed position and this amount is due to changes in the Company's projected capital expenditures.[3486] The Company asserts the Commission should approve the requested amount.

The Company notes its original position for projected FIT expense was $46.009 million. Although no party took issue with the Company's proposed FIT expense, Staff used different revenue and expense assumptions. The Company does not oppose the method Staff used to calculate its FIT expense, but the Company does oppose several of Staff's expense assumptions which impact the FIT expense. Consumers Energy requests that the Commission adopt Consumers Energy's calculation of FIT expense in the amount of $48.064 million.[3487]

In its brief, Staff recommends total property tax expense of $278,305,000 which is $1,684,000 less than the Company's projected total property tax.[3488] The difference

[3484] Company brief, p. 392.
[3485] Company brief, p. 392.
[3486] Company brief, p. 392; Appendix C.
[3487] Company brief, p. 393; Appendix C.
[3488] Staff brief, p. 130; Appendix C.

stems from capital expenditure adjustments, which reduce real and personal property taxes.[3489]

Staff recommends a total federal income tax (FIT) expense of $56,269,000, which is $8,217,000 more than the Company's rebuttal projection of $48,052,000. Staff's adjustments to the Company's projected revenues and expenses are responsible for the difference. Staff recommends the ALJ, and the Commission recalculate federal income tax expense based on all the decisions in their respective PFD and final Order.[3490]

In her brief, the Attorney General references the adjustments that should be made to the Company's proposed capital expenditures which lower the amount of property tax expense that will be incurred.[3491] She notes that if the Commission adopts the Attorney General's recommendations, the property tax expense should also be reduced by approximately $3.8 million.[3492]

This PFD notes that all tax expense should be recalculated consistent with the final Commission order.

F. Allowance for Funds Used During Construction

Mr. Daly presented the projected test year AFUDC.[3493] He explained that AFUDC is an accounting convention that recognizes the costs of financing certain construction projects by the transfer of interest and equity cost from the income statement to CWIP

[3489] Staff brief, p. 130.
[3490] Staff brief, p. 131.
[3491] Attorney General brief, p. 196.
[3492] Attorney General brief, p. 196.
[3493] 3 Tr 1058; Ex. A-13, Sch. C-11.

on the balance sheet.[3494] He noted that AFUDC increases revenue and net operating income, reducing the amount of rate relief and is designed to offset the return built into the case for AFUDC-eligible CWIP.[3495] According to Mr. Daly, the criteria for applying AFUDC to a construction project requires on-site construction activities of more than six months duration and an estimated plant cost (excluding AFUDC) in excess of $50,000.[3496] Noting that it did not revise its original calculations, and Staff did not recommend any adjustments, Consumers recommends approval of the test year jurisdictional AFUDC level of $16.026 million.[3497]

Since no party has recommended an adjustment, this PFD recommends the Commission adopt Consumers' projected AFUDC for the test year of $16.026 million.

G. Calculation of Adjusted Net Operating Income

Consumers presents its total operating revenues of $5,020,623,000, net operating income of $691,658,000, and after adjusting for AFUDC, an ANOI of $707,685,000.[3498] Consumers states that the NOI and ANOI have been revised slightly to reflect the agreed removal of $250,023 in ARP-Collaboration capital expenditures for 2025.

Mr. Nichols presented Staff's projected net operating income of $737,882,000.[3499] According to Mr. Nichols, the main factors driving Staff's overall adjustment are its increase to sales revenue with PSCR offset and its reduction to O&M

[3494] 3 Tr 1058.
[3495] Id.
[3496] Id.
[3497] Consumers initial brief, p. 394, App. C1; Ex. S-3, Sch. C-1 and Rev. Ex. A-213.
[3498] Consumers initial brief, p. 395, App. C1; Ex. A-213.
[3499] 6 Tr 4565; Ex. S-3, Sch. C-1.

expense, depreciation and amortization expense, and property tax expense.[3500] Staff's brief decreased its proposed total NOI to $737,124,000.[3501] The Attorney General's proposed ANOI is $831,559,000.[3502]

The ANOI should be recalculated based on the Commission's findings in its final order. The ANOI based on the determinations in this PFD will be available in the docket on or before February 6, 2026.

VII.

COST OF SERVICE, RATE DESIGN, AND TARIFF ISSUES

A Cost-of-Service Study (COSS) by rate class is a systemic functionalization, classification, and allocation of a utility's fixed and variable costs to provide service. A COSS has two broad purposes. First, the COSS can identify and separate costs associated with the utility's production and distribution of electricity into the jurisdictional electric rate classes. Second, it can determine relative contribution to jurisdictional earnings from each of the utility's jurisdictional electric rate classes.[3503]

A. Cost of Service

Ms. Davis testified that a cost of service study (COSS) is used to quantify the embedded cost of serving various customer classes and to guide the design and development of customer rates.[3504] She explained there are three steps in performing a COSS: 1) functionalization involves the identification and separation of plant and expenses into specific categories based on the activity or function that the cost is

---

[3500] 6 Tr 4565; Ex. S-3, Sch. C-1.1.
[3501] Staff initial brief, p. 93, App. C1.
[3502] Ex. AG-58.
[3503] Case No. U-20697, Order, December 17, 2020, p. 273.
[3504] 4 Tr 2646.

incurred to provide or support; 2) classification involves categorizing costs as demand, customer, or energy related according to the primary cost drivers; and 3) allocation involves assigning costs to each customer class using a variety of factors that correlate to the identified cost drivers.[3505] She stated that the fundamental principle guiding the assignment of costs in the COSS is cost causation, meaning the costs assigned to a class or group of customers should reflect how those customers drive or influence the utility's costs.[3506] She also testified about the development of the Company's allocation factors (or schedules), which are used to allocate to each customer class its utilization of a particular part of the electric system.[3507]

Ms. Davis testified that because the Company is proposing changes to the COSS methodologies previously approved by the Commission, it is sponsoring two versions of the COSS.[3508] She stated that the Version 1 COSS is used for comparison purposes, while the Company is proposing to use the Version 2 COSS for rate design.[3509]

Ms. Davis sponsored Exhibit A-16, Schedule F-1, which contains the results of the Version 1 COSS.[3510] She stated that Version 1 employs the methodologies previously adopted by the Commission in Case No. U-21585, with routine updates for historic and test year data including updates to the allocation schedules.[3511] Ms. Davis stated that Version 1 incorporates three additional revisions. First, there was a correction to the allocation of the PowerMI-Drive (PMD) and PowerMI-Fleet (PMF)

[3505] 4 Tr 2646.
[3506] 4 Tr 2646.
[3507] 4 Tr 2646-2648. The schedule numbers are shown in Exhibits A-16, Schedule F-1, and A-16, Schedule F-1.1, pp. 7-12.
[3508] 4 Tr 2644.
[3509] 4 Tr 2649.
[3510] 4 Tr 2648.
[3511] 4 Tr 2644, 2649.

amortization expense to align with the Commission's approved treatment of program costs in Case No. U-21389.[3512]

Second, the Company updated distribution cost categories for land, lines, and substation assets to align with the results of the Electric Asset Categorization (EAC) report.[3513] Ms. Davis stated that the EAC report breaks out plant and related depreciation accounts for distribution substations (FERC 361 and 362), batteries (FERC 363), high voltage distribution (HVD) overhead (OH) and underground (UG) lines (FERC 364-367), and land (FERC 360) into more detailed categories.[3514] She added that a combination of process complexity, outdated technology, and the loss of institutional knowledge made it difficult to continue to maintain and run the previous report. As a result, the Company worked with a third-party consultant to improve the report and increase transparency around how assets are assigned in the COSS.[3515]

Ms. Davis provided an overview of the new EAC report process.[3516] She stated that the new report will have an impact on production costs because it includes a breakout of Generation Step Up (GSU) facilities (consisting of substations, lines, and other assets that support bringing power from generation facilities to the distribution system), which are classified as distribution for FERC accounting purposes but are in service of or driven by investment in production facilities.[3517] Ms. Davis also presented a

---

[3512] 4 Tr 2649-2650.
[3513] 4 Tr 2649-2656.
[3514] 4 Tr 2650.
[3515] 4 Tr 2651.
[3516] 4 Tr 2651.
[3517] 4 Tr 2651-2652. Ms. Davis added that GSU-related distribution plant identified in the EAC report is included in the COSS balance of other production plant. *Id*.

more detailed overview of the changes to the various cost categories resulting from the new EAC report in Tables 1 through 8 at 4 Tr 2652-2656.

Third, the Version 1 COSS incorporates a breakout and allocation of the costs for three Digital Customer Operations (DCO) projects (Move In/Movie Out (MIMO) 3.0, Commercial and Industrial (C&I) Online Account Management, and MIMO Digital Redesign) in compliance with the final order in Case No. U-20963.[3518] Ms. Davis stated that if these projects were not separately broken out, costs would be included in GC&I cost categories, which are functionalized and allocated to all customer classes on the basis of labor, consistent with how all other DCO IT project costs are treated. She stated that the COSS allocates MIMO 3.0 project costs to the residential customer class because the project was developed to give residential customers a tool for self-service MIMO transactions.[3519] Regarding the C&I Online Account Management project, Ms. Davis testified that it has been renamed the Multi-Account Online Account Management (MAOAM) project and the scope of the project was expanded to give all customers (including residential customers) the ability to manage multiple accounts through a single login.[3520] She added that because this project will support customers across various rate classes, the Company believes it should be allocated in the same manner as other IT projects, negating the need to separately identify and breakout costs in the COSS. For this reason, the Company requests that the Commission no longer require a separate breakout of costs for this project in future cases.[3521]

[3518] 4 Tr 2649-2650, 2656-2658. Table 9 at 4 Tr 2657 shows the test-year costs for the three projects; there are no projected costs for the MIMO Digital Redesign project.
[3519] 4 Tr 2657.
[3520] 4 Tr 2657-2658.
[3521] 4 Tr 2658.

Ms. Davis next sponsored Exhibit A-16, Schedule F-1.1, which summarizes Version 2 of the test year COSS. She stated that Version 2 starts with the Version 1 COSS and incorporates Company proposals to: 1) provide a more detailed breakout and allocation of customer advances; and 2) update the allocation of OH line O&M expenses.[3522]

Ms. Davis testified that customer advances—potentially refundable customer contributions that are made to offset the cost of extending facilities to serve a customer—are treated as a reduction to rate base and are currently allocated to customers based on their share of total distribution plant in service (Allocator 309).[3523] She stated that with the updated EAC report and breakout of distribution assets into more detailed categories, the Company believes it is appropriate to include a more detailed breakout of the customer advances that fund those assets.[3524] Version 2 breaks out customer advances by the customer's connected voltage level (e.g. Voltage 1, 2, or LVD) and allocates the credit to that same group of customers using Class Peak.[3525]

Next, Ms. Davis presented Table 10 at 4 Tr 2660, which summarizes the current and proposed allocation of Distribution O&M in FERC Accounts 582-586 and 591-597. She noted that the majority of Distribution O&M expenses are broken out by FERC account and in some cases voltage level and are currently allocated to rate classes based on their assignment of related plant in service (PIS) accounts.[3526] She stated that

---

[3522] 4 Tr 2658.
[3523] 4 Tr 2658.
[3524] 4 Tr 2659.
[3525] 4 Tr 2659.
[3526] 4 Tr 2659.

the Company is proposing new allocators for FERC accounts 583 and 593 (OH line) O&M expenses to be consistent with the logic and allocation of costs for similar distribution O&M accounts.[3527] She testified that Voltage 1 OH line O&M is currently allocated using a 4CP allocator that is not used to allocate any other distribution related costs in the COSS; the Company is instead proposing to allocate these costs using Voltage 1 OH line PIS. Voltage 2 OH line O&M is currently being allocated using Class Peak @ Voltage 2, which Ms. Davis stated would be reasonable if all Voltage 2 OH line PIS were assigned using the allocator but that is not the case. The Company is proposing to allocate these costs using Voltage 2 OH line PIS. Finally, Ms. Davis stated that LVD OH line O&M is currently being allocated using a PIS allocator that includes both LVD and HVD PIS, which causes HVD customers to be assigned LVD related O&M; in Version 2, the Company proposes to allocate these costs using LVD OH line and services PIS.[3528]

Ms. Davis testified that the impact of the Company's Version 2 proposals on the different COSS rate classes is summarized in Table 11 and illustrated in Figure 1 at 4 Tr 2662. She stated that the Company's proposed Version 2 COSS would increase Residential, Commercial Secondary, and Lighting costs by 0.9%, 0.2% and 0.4%, respectively, compared to Version 1, while Primary costs would decrease 2.5%.[3529]

In their initial brief, MNSC state that concerns raised by CUB witness Bunch involving Consumers' method for allocating reliability improvements without considering customer benefits is "an issue that may be deferred to a future proceeding" and MNSC

[3527] 4 Tr 2660-2661.
[3528] 4 Tr 2661.
[3529] 4 Tr 2662.

"supports taking no action on this issue in this proceeding."[3530] The remaining disputed issues involving the Company's COSS are addressed below.

1. Distribution Cost Allocation and the EAC Report

MNSC witness Palmer testified that Consumers' COSS disproportionately and inappropriately assigns distribution costs to lower voltage or smaller customers.[3531] She stated that historically, Consumers has excluded customers taking service at higher voltage levels from cost allocation for certain infrastructure to account for the fact that such customers did not contribute to system costs at lower voltage levels.[3532] She stated that the theory supporting such differentiation is that higher voltage customers do not benefit from the lower voltage distribution network because power flows in one direction (from high to low voltage).[3533] But Ms. Palmer stated that one-way power flow is no longer the reality and 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 previously only benefitted from centralized generation delivered at the transmission or primary level.[3534] She stated that 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.[3535]

[3530] MNSC brief, 82-84.
[3531] 6 Tr 3917.
[3532] 6 Tr 3919.
[3533] 6 Tr 3919.
[3534] 6 Tr 3919.
[3535] 6 Tr 3920.

Ms. Palmer testified that Consumers has acknowledged bidirectional power flow on its distribution system.[3536] She stated that the Company anticipates between 2.4 and 3.5 GW of solar DG penetration by 2030, causing two-way flows.[3537] She added that Consumers justifies the importance of a DER Management System (DERMS), in part, based on bidirectional power flow, and the Company has called a DERMS "critical for managing bi-directional power flows."[3538] Ms. Palmer stated that Consumers is increasingly planning and designing its power system to be bidirectional and that the Company expects to produce reports in the future demonstrating the extent of bidirectional power flow.[3539]

Ms. Palmer disagreed with Consumers' new EAC report and resulting COSS allocators.[3540] She testified that stricter assignment of costs to downstream-voltage customers does not reflect customers' use of the power system since two-way power flows are becoming more common.[3541] She added that most of the new EAC categories and corresponding COSS allocations of all low-voltage resources strictly to low-voltage customers introduce a false precision that is no longer fully representative of reality and is thus unreasonable and out of sync with the changing grid.[3542]

Ms. Palmer recommended that the Commission reject Consumers' proposed new distribution COSS allocations to downstream-voltage customers based on the updated EAC report. She stated that new EAC categories that specifically isolate high-

---

[3536] 6 Tr 3919.
[3537] 6 Tr 3919-3920.
[3538] 6 Tr 3920.
[3539] 6 Tr 3920.
[3540] 6 Tr 3921.
[3541] 6 Tr 3921.
[3542] 6 Tr 3921.

voltage costs, such as Consumers' new V1 and V2-13 only allocators, do not necessarily fit this description and may be appropriate. She further recommended that the Company should reconsider existing voltage differentiations already built into its COSS, with related recommendations in its next rate case. And she added that as the Company develops analysis of bidirectional flow on its power system, it should incorporate such empirical data into the EAC report or other power system mapping to identify the extent to which higher voltage customers utilize and should pay for downstream assets.[3543]

Ms. Palmer continued by testifying that Consumers categorized 100% of distribution batteries as LVD, meaning they are allocated only to low-voltage customers (in this case, voltage level 3 and 4).[3544] Ms. Palmer stated that Consumers justified this allocation as being consistent with the way the COSS treats other demand-related distribution plant and allocates costs to the customer classes connected to (or downstream of) the voltage level of that equipment.[3545] Ms. Palmer opined that the allocation of battery costs should not be limited to low-voltage customers.[3546] She noted that Consumers stated in response to discovery that it is not aware of any engineering literature or manuals that specifically state that batteries serve only voltage level 3 and 4 customers and that distribution-related battery plant is deployed to support the electric distribution system (e.g., capacity deferral, voltage support, resiliency, etc.).[3547] Ms.

[3543] 6 Tr 3921.
[3544] 6 Tr 3921-3922.
[3545] 6 Tr 3922.
[3546] 6 Tr 3922.
[3547] 6 Tr 3922.

Palmer therefore recommended that Consumers allocate distribution battery costs to all distribution customers.[3548]

In rebuttal, Ms. Davis testified that Ms. Palmer appears to conflate her concerns about the allocation factors applied to LVD assets and the EAC report itself, which simply serves to provide more robust detail on the Company's substation, land and HVD line distribution assets. She stated that 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. She stated that 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.[3549] Ms. Davis added that while Ms. Palmer proposes that the Commission reject the Company's allocation of distribution costs to LVD connected customers, she does not offer any specific alternative allocator(s) for the Commission to consider.[3550]

Regarding the Company's voltage categories, Ms. Davis testified that 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.[3551] She added that Ms. Palmer's vague recommendation to reconsider the Company's voltage classifications is not accompanied by any proposed alternative or clear benefit/value.[3552]

[3548] 6 Tr 3922.
[3549] 4 Tr 2670.
[3550] 4 Tr 2670.
[3551] 4 Tr 2670.
[3552] 4 Tr 2670.

Ms. Davis testified that while it appears Ms. Palmer is arguing that the EAC report categories offer more precision than necessary, 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.[3553]

Referencing Mr. McPhail's rebuttal testimony (addressed below), Ms. Davis testified that the extent of bidirectional power flow between the LVD and HVD system is de minimis. She stated that the rare occasion when bidirectional power flow occurs does not fundamentally change what has caused or driven the Company to build out and maintain the infrastructure on its LVD system. Ms. Davis added that Ms. Palmer's argument about bidirectional power flow is not new or suddenly more relevant because of the EAC report, which only serves to provide more transparent information about the Company's assets.[3554]

Regarding batteries, Ms. Davis testified that 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).[3555] She stated that 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.[3556] She stated that currently, the only distribution batteries in service are connected to the LVD system, which is why they are allocated to LVD customers.[3557] Ms. Davis added that while Ms.

[3553] 4 Tr 2670-2671.
[3554] 4 Tr 2671.
[3555] 4 Tr 2671.
[3556] 4 Tr 2672.
[3557] 4 Tr 2672.

Palmer argues that batteries benefit customers across all distribution levels—presumably a reference to her argument on bidirectional power flow—those rare occurrences of bidirectional power flow are not what is causing the Company to invest in LVD batteries.[3558]

Mr. McPhail described the extent of bidirectional power flow between the LVD and HVD system as de minimis, citing distribution substation load data showing 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. He stated that while the Company is able to track the occurrence of bidirectional flow at certain substations using SCADA data, 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. Mr. McPhail testified that 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.[3559] He added that 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.[3560]

ABATE witness Andrews testified that Ms. Palmer provided no engineering analysis, empirical data, or system studies to demonstrate that higher voltage customers actually use, depend upon, or benefit from the lower voltage distribution

---

[3558] 4 Tr 2672.
[3559] 3 Tr 1753.
[3560] 3 Tr 1753.

network.[3561] He stated that high-voltage customers are served upstream of the LVD system and do not utilize those facilities; therefore, they do not cause the associated costs. He stated that assigning low-voltage system costs to high-voltage customers would distort cost responsibility and create cross-subsidies that violate cost-causation principles.[3562]

Mr. Andrews further testified that while distributed generation can cause limited instances of reverse flow at the local level, neither Ms. Palmer nor Consumers has presented any evidence that such flows are significant or system-wide.[3563] He stated that the Company is still developing analytical tools to measure the extent of bidirectional flow, and until measurable data demonstrates that higher-voltage customers are materially served by lower-voltage assets, the long-established allocation method should remain unchanged.[3564]

Mr. Andrews testified that Ms. Palmer's recommendation to allocate the costs of distribution batteries to all distribution customers lacks both engineering evidence and analytical support.[3565] He stated that Consumers has documented that its distribution batteries are connected at voltages between 8.32 kV and 24.9 kV, which are classified as low-voltage distribution.[3566] He stated that the batteries are installed to support local circuits, address local reliability or voltage issues, and manage load on low-voltage feeders, and they are not part of the transmission or high-voltage system used by

---

[3561] 6 Tr 3829-3830.
[3562] 6 Tr 3830.
[3563] 6 Tr 3830.
[3564] 6 Tr 3830.
[3565] 6 Tr 3832.
[3566] 6 Tr 3832.

Primary customers.[3567] He added that allocating those costs to customers who do not physically or operationally use those facilities would violate the cost-causation principle.[3568]

Kroger witness Robertson testified that traditional cost allocation principles indicate that the customer who *causes* the need for the utility to incur certain costs should be allocated those costs, which is not the same thing as allocating embedded costs based on an alleged *benefit*.[3569] He asserted that Ms. Palmer's recommendation seeks to allocate low-voltage distribution costs to higher voltage customers based on alleged benefits, instead of cost causation.[3570] He further stated that the low-voltage distribution system exists to serve low-voltage customers and would not exist if there were only high-voltage customers, and the possibility of bidirectional flow of electricity does not indicate that the low-voltage distribution system was built to serve high-voltage customers.[3571]

Mr. Robertson further testified that Ms. Palmer failed to provide any evidence to demonstrate that bidirectional flows of electricity benefit higher voltage customers.[3572] He stated that the Company has acknowledged the possibility that power may sometimes flow from lower voltage to higher voltage distribution equipment, but this does not constitute evidence that such flows occur.[3573] He added that even if bidirectional power flows may occasionally occur, Ms. Palmer did not provide evidence

---

[3567] 6 Tr 3832.
[3568] 6 Tr 3832.
[3569] 5 Tr 3422.
[3570] 5 Tr 3424.
[3571] 5 Tr 3422.
[3572] 5 Tr 3422, 3424.
[3573] 5 Tr 3423.

regarding the frequency or magnitude of such occurrences.[3574] He further noted that Consumers has indicated that bidirectional power flows cause challenges for the Company and is an issue that will need to be mitigated.[3575]

In briefing, Consumers argues that the Commission should reject Ms. Palmer's recommendations because they are unsupported by appropriate facts or by a correct recognition of cost-causation principles.[3576] The Company adds there is no support for Ms. Palmer's assumption that upstream commercial and industrial customers are benefiting from bidirectional power flow, even if the concept of who benefits from a general class of investments were a proper basis for allocating costs (which the Company asserts it is not).[3577]

MNSC argue that the Company proposes to use the EAC report (which is not in evidence) to make an important change to its method of allocating distribution costs. They state that the Company previously allocated the cost of distribution assets based on class peak at the highest voltage connected to the asset, but the new method allocates costs based on the highest voltage level downstream of the asset.[3578] Citing MCL 460.11(1), MNSC argue that Consumers has the burden to prove that its proposed change ensures that rates are equal to the cost of providing service and that each customer class will be assessed for its fair and equitable use of the electric grid.[3579]

[3574] 5 Tr 3423.
[3575] 5 Tr 3423.
[3576] Consumers brief, 407.
[3577] Consumers brief, 405.
[3578] MNSC brief, 75.
[3579] MNSC brief, 76.

They assert that the allocation of distribution assets only to downstream customers is a change in method that has not been previously approved.[3580]

Citing Ms. Davis's cross-examination testimony, MNSC argue that the change included in both version 1 and 2 of the COSS has cost consequences, but Consumers does not know what those consequences are and has not assessed them.[3581] They assert that the Commission should not adopt a change in cost allocation without any information about the cost consequences of that change.[3582] MNSC further argue that the assumption underlying the proposed change in allocation distribution plant costs—that power only flows from the high to low side of distribution assets—is not accurate given bidirectional power flow and will grow less accurate as Consumers connects more distributed solar to its system.[3583] They state that eliminating the cost responsibility of the higher-level voltage customers for equipment that flows down to lower voltage customers at a time when the Company plans to grow the use of two-way flows is not prudent, adding that if approved, Consumers has no plans to revisit the new allocations as it implements the distribution plan and bidirectional flows increase.[3584]

MNSC recommend that the Commission deny approval of Consumers' proposed change and require the Company to maintain the U-21585 allocators listed in Tables 1, 3, 5, and 7 of Ms. Davis's direct testimony for distribution substations and equipment, distribution HVD OH lines, distribution HVD UG lines, and distribution land.[3585]

[3580] MNSC brief, 76-77.
[3581] MNSC brief, 77.
[3582] MNSC brief, 78.
[3583] MNSC brief, 79.
[3584] MNSC brief, 80.
[3585] MNSC brief, 81-82.

Regarding distribution batteries, MNSC continue Ms. Palmers' argument that costs should be allocated to all distribution customers because batteries serve the whole distribution system, not just the lowest voltage parts of it.[3586]

In its initial brief, Staff states that it takes no issue with the Company's updated EAC report process and expanded COSS cost categories, as it provides more detail and accuracy in assigning costs throughout its distribution system.[3587] Regarding bidirectional power flows and purported benefits to higher voltage customers, Staff states that these supposed power flows have not been quantified and are very minimal.[3588] Staff further states that costs are not assigned based on benefit; rather, costs are assigned based upon cost causation, which for the distribution system is peak demand by voltage level.[3589] Staff adds that bidirectional power flows have not been shown to affect these peak demands in any significant way and should not be considered when allocating distribution system costs.[3590]

In reply, Consumers refutes MNSC's claim that the EAC report results in a change to the methodology of allocating distribution assets, citing Ms. Davis's testimony to the contrary.[3591] The Company states that it is still using the same methodology of breaking out costs by FERC account and voltage level and using a Class Peak allocator to allocate costs to customers attached to and downstream of that equipment.[3592] It states that the only difference is that the Company now has more granular detail about

---

[3586] MNSC brief, 84-85.
[3587] Staff brief, 157.
[3588] Staff brief, 157.
[3589] Staff brief, 157.
[3590] Staff brief, 157.
[3591] Consumers reply, 21.
[3592] Consumers reply, 21.

the costs in those FERC accounts, which allows the Company to apply the Class Peak allocators more precisely.[3593]

Consumers further disagrees with MNSC's claim that, where costs were previously allocated based on class peak at the highest voltage connected to the asset, they will now be allocated based on the highest voltage level downstream of the asset.[3594] Addressing Ms. Davis's cross-examination testimony cited by MNSC to support their argument, the Company states that in Case No. U-21585, Voltage 2, 3, and 4 customers were paying for some costs that will now be solely allocated to Voltage 1 customers because assets were previously grouped into a single category with no way to differentiate them, resulting in each voltage group theoretically paying for some portion of the other group's assets.[3595] The Company asserts that the EAC disentangled the assets for both groups, shifting costs in both directions, so that each group is now only paying for its own assets and no group is paying for costs it did not cause.[3596] It also disputes that the EAC shifts costs from high voltage customers to lower voltage customers, noting that under its proposal Rate GPD Voltage 1 customers will experience a 145% increase in the distribution component of their rates.[3597]

In their reply brief, MNSC reiterate their argument that the Company carries the burden of demonstrating that its proposed change to the allocation of distribution asset costs should be approved.[3598] MNSC dispute Staff's claim that costs are assigned based on cost causation rather than benefit, arguing that a utility incurs costs to provide

---

[3593] Consumers reply, 21.
[3594] Consumers reply, 22.
[3595] Consumers reply, 22, citing 4 Tr 2690.
[3596] Consumers reply, 22.
[3597] Consumers reply, 23, citing Exhibit A-16, Schedule F-3.0, p. 11.
[3598] MNSC reply, 5.

the benefits of electric service to customers and referencing its discussion of allocating costs according to benefits in the AMI section of its initial brief.[3599] MNSC find it "disappointing that Staff is willing to sign off on the Company's substantial change to the allocation of distribution costs without any information about the magnitude of costs the change will shift from larger customers downstream to smaller ones" and state that they are unaware of any precedent where the Commission approved a change in cost allocation method without any projections of how the change will impact revenues collected from different customer classes.[3600]

ABATE argues that the customers who cause distribution costs and are served by these assets are lower-voltage customers downstream from the assets, and there is no evidence that upstream commercial and industrial customers are benefiting from bidirectional power flow.[3601] It argues that vague commentary about the future of bidirectional power flow does not provide a reasonable basis for rejecting the Company's proposal, which is consistent with the way in which the Company's system currently operates.[3602] ABATE states that under the Company's proposal, customers who are served by a substation will be allocated the associated costs, which is a straightforward application of cost causation and cost of service principles.[3603] It further argues that as the proponent of a change to the existing allocation of distribution battery costs, MNSC bear the burden of demonstrating that their change would better ensure

[3599] MNSC reply, 5-6.
[3600] MNSC reply, 6.
[3601] ABATE reply, 26.
[3602] ABATE reply, 26-27.
[3603] ABATE reply, 27.

rates equal to the cost of service.[3604] ABATE asserts that MNSC failed to meet this burden as their proposal is based on general and inadequately supported assertions regarding potential system benefits and not on actual data or operational evidence.[3605]

This PFD recommends that MNSC's objection to the EAC report should be rejected. Consumers explained the need for updating the EAC report, provided an overview of the new report process, and reviewed changes to various cost categories that result from the report's more detailed breakout of assets. In addition, Consumers adequately rebutted MNSC's claim that the EAC report represents a new method of allocating distribution costs. In its reply brief, Consumers explained that it continues to break out costs by FERC account and voltage level and use a Class Peak allocator to allocate costs to customers attached to and downstream of that equipment.[3606] The EAC report now allows the Company to apply the Class Peak allocators more precisely, and Consumers illustrated how certain assets that were previously grouped into a single category with no way to differentiate them are now "disentangled" so that customer groups are not paying for other groups' assets.[3607] This PFD also finds there is not adequate evidence showing that the EAC report results in costs being unfairly shifted from low- to high-voltage customers.

Furthermore, this PFD finds there is no basis to reject Consumers' COSS or to otherwise alter its allocation methods due to bidirectional power flows.[3608] Company

---

[3604] ABATE reply, 28-29.
[3605] ABATE reply, 29.
[3606] Consumers reply, 21.
[3607] Consumers reply, 22.
[3608] As the proponent of altering the Company's established allocation methods, MNSC have the burden of showing that their proposal better ensures rates are equal to the cost of service. See June 15, 2015 order in Case No. U-17689, pp 18-19.

witness McPhail explained that bidirectional power flows between the LVD and HVD system are de minimis and that the Company is currently unable to track such flows across the distribution system.[3609] It would be premature and imprudent to modify cost allocations without adequate, quantitative data demonstrating that lower-voltage assets are being used to serve higher-voltage customers. Similarly, MNSC have not supported their argument that distribution batteries should be allocated to all distribution customers. These batteries are only connected to the LVD system and there is inadequate evidence that they serve high-voltage customers. In short, MNSC failed to establish that the Company's method for allocating these costs is somehow unreasonable or imprudent.[3610]

2. Advanced Metering Infrastructure Cost Allocation

Consumers allocates meter PIS using a weighted customer allocator (allocator 170) that takes into account the number of customers and the cost of the meter since primary rate customers' meter costs are higher than those for residential customers.[3611] MNSC witness Palmer testified that this approach does not reflect the realities of an evolving power system.[3612] She stated that while the main purpose of meters was once customer billing, advanced meters serve a broader range of functions, including demand management, and that the benefits of these meters (including reduced energy theft, peak demand reduction, and energy consumption savings) flow beyond individual

---

[3609] 3 Tr 1753.

[3610] While it is unnecessary here to determine the propriety of a benefits-focused approach to cost allocation, this PFD notes its findings with respect to AMI meters (below) that the Commission has historically followed traditional cost-causation principles and that the allocation of costs to a class of customers that does not use the asset is unlikely to comply with MCL 460.11(1).

[3611] 4 Tr 2672.

[3612] 6 Tr 3911.

customers.[3613] She added that the functionality and benefits associated with Consumers' AMI meters change cost causation for these meters compared to traditional meters.[3614]

Ms. Palmer proposed that Consumers classify AMI meter costs across a combination of customer, demand, and energy because AMI meters provide services and benefits that can be categorized into each of those three cost drivers. She noted that in the Company's last AMI business case filed in Case No. U-21389, of total expected electric smart grid program benefits, demand-related benefits totaled 17% while energy-related benefits totaled 36%. She therefore proposed an initial classification approach that treats AMI meter costs as 36% energy-related, 17% demand-related, and 47% customer-related.[3615] She also recommended that Consumers produce its business case benefit analysis in future rate cases and update this classification accordingly.[3616] Ms. Palmer stated that her approach would allocate fewer costs to small customers and greater costs to larger customers.[3617] She added that she did not implement her proposal in the Company's COSS to determine its impact because the COSS does not permit the testing of changes at this level of granularity, and she suggested that the Company is best qualified to adapt its model to include this new classification and allocation approach if the Commission approves it.[3618] In support of her recommendation, Ms. Palmer noted that the Maryland Public Service Commission approved a benefits approach for allocating AMI costs, and the

---

[3613] 6 Tr 3912.
[3614] 6 Tr 3912.
[3615] 6 Tr 3913.
[3616] 6 Tr 3913.
[3617] 6 Tr 3914-3915.
[3618] 6 Tr 3914.

Colorado Public Utilities Commission has approved AMI meter classification as more than customer related.[3619]

In rebuttal, Ms. Davis responded that 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.[3620] She stated that the existence of other benefits does not change the fact that the addition of a customer requires a meter, and she stated that the Company's weighted customer allocator appropriately captures how customers drive the utility's investment in metering infrastructure.[3621] Ms. Davis added that AMI meters and the benefits they provide are not new and that the Commission has consistently relied on the weighted customer allocator to fairly apportion meter costs amongst customer classes.[3622]

Ms. Davis further testified that the total impact to customers from Ms. Palmer's proposed changes is unclear and difficult to determine in part because Ms. Palmer does not address the allocation of non-AMI meters that are included in the Company's meter plant. She stated that less than 0.04% of AMI meters serve primary rate customers, yet Ms. Palmer's proposed composite allocator would assign 22% of AMI meter costs to primary rate customers.[3623]

Ms. Davis described Ms. Palmer's categorization of the avoided costs from the AMI business case as oversimplified.[3624] She stated that Ms. Palmer assumes that the benefits from AMI Induced Conservation & Energy Efficiency accrue to all customers in

---

[3619] 6 Tr 3915-3916.
[3620] 4 Tr 2672.
[3621] 4 Tr 2672-2673.
[3622] 4 Tr 2673.
[3623] 4 Tr 2673.
[3624] 4 Tr 2673.

proportion to the total energy allocator based on an apparent justification that the benefit is energy related so must accrue (and should be allocated) to all customers based on energy use.[3625] Ms. Davis stated that this view provides no consideration or comparison of whether energy use truly captures the realization of the different benefits to customers (e.g. system benefits from lower peak energy usage and the AMI customer's direct energy savings).[3626] Ms. Davis also faulted Ms. Palmer's proposal to divide the entire AMI meter cost between these benefits without considering or comparing the cost of a non-AMI meter to calculate the AMI "premium" incurred to realize those benefits.[3627] Ms. Davis concluded that 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.[3628]

ABATE witness Andrews testified that the Company's current treatment of AMI meters as entirely customer-related is correct and consistent with cost-causation principles and long-standing Commission precedent.[3629] He stated that every customer, regardless of their size or usage pattern, must have a meter to receive service and be billed accurately, and the cost of metering is caused by the existence of the customer relationship, not by how much energy the customer consumes or demands at peak.[3630] According to Mr. Andrews, AMI technology does not change this fundamental causation, it merely provides an updated means of measuring and communicating

---

[3625] 4 Tr 2673-2674.
[3626] 4 Tr 2674.
[3627] 4 Tr 2674.
[3628] 4 Tr 2674.
[3629] 6 Tr 3827.
[3630] 6 Tr 3827.

customer usage.[3631] He stated that the Commission has repeatedly approved classifying meters as customer-related, including Consumers' AMI investments, and there is no new evidence to justify departing from this standard.[3632]

Mr. Andrews testified that allocating costs based on alleged benefits to various customer classes conflicts with the fundamental principle of cost allocation that customers should be allocated the costs they cause.[3633] He stated that while AMI systems provide some operational benefits, those benefits are incidental and system wide, not direct drivers of metering costs, and that any secondary energy or demand benefits are properly captured in operational savings and not in the classification of the meter plant itself.[3634] He added that any alleged benefits from AMI meter usage will go to the customers and classes that use them.[3635]

Mr. Andrews testified that residential customers represent 88% of Consumers' installed AMI meters, Commercial represents 11.97%, and Primary represents just 0.04%.[3636] He stated that because Primary customers represent essentially 0% of the AMI meters, they neither cause these costs nor will they see any benefits from AMI.[3637] Mr. Andrews came to the same conclusion regarding customers that take service under Rate Schedules GPD, GPTU, and EIP, none of whom use AMI meters.[3638] Mr. Andrews concluded that Ms. Palmer's proposal would unfairly shift approximately $59.5 million of

---

[3631] 6 Tr 3827.
[3632] 6 Tr 3827.
[3633] 6 Tr 3827.
[3634] 6 Tr 3827-3828.
[3635] 6 Tr 3828.
[3636] 6 Tr 3828.
[3637] 6 Tr 3828.
[3638] 6 Tr 3828.

AMI meter costs to the Primary Customer classes, without evidence showing that those customers cause or benefit from these costs.[3639]

Kroger witness Robertson testified that Ms. Palmer's recommended energy, demand, and customer weightings do not align with quantifiable AMI benefits because they are based on estimated and forecasted benefits from the Company's entire Smart Grid Program, as opposed to just the benefits that are projected to result from the Company's AMI infrastructure.[3640] He stated that Ms. Palmer's recommendation would modify the cost allocation based on actual and estimated benefits, instead of cost causation.[3641] He testified that while he is not offering a legal opinion, MCL 460.11(1) states that rates should be equal to the cost of providing service, indicating that costs should be allocated based on cost causation and not benefits.[3642] Mr. Robertson testified that to the extent certain customer classes leverage the benefits of AMI to reduce costs on the system by reducing their coincident peaks, that will reduce the costs that would be allocated to that customer class in a COSS.[3643] He added that a COSS allocates actual embedded costs, not hypothetical avoided costs such as the possibility of avoided or deferred production and distribution investments due to changing customer behavior.[3644] Mr. Robertson concluded that the Commission should reject Ms. Palmer's proposal and instead approve Consumers' cost allocation based on weighted customers.[3645]

[3639] 6 Tr 3829.
[3640] 5 Tr 3416-3418.
[3641] 5 Tr 3418.
[3642] 5 Tr 3418.
[3643] 5 Tr 3419.
[3644] 5 Tr 3419.
[3645] 5 Tr 3419-3420.

In its initial brief, Consumers reiterates its opposition to Ms. Palmer's proposed AMI meter cost allocator.[3646] The Company also summarizes testimony by Mr. Kelly regarding the AMI business case and argues that the Commission should reject Ms. Palmer's recommendation to produce an AMI benefit analysis because the Commission already determined in Case No. U-21389 that the AMI business case was no longer needed since the value of the reporting is less about supporting a business case for meters that had long been installed. The Company is now providing AMI value-focused metrics (as shown in Exhibit A-133) consistent with the Commission's requirement.[3647]

MNSC cite various legal authorities and case law in support of their claim that federal and state law requires AMI costs to be allocated according to program benefits.[3648] They argue that the Commission adheres to cost causation principles requiring utility costs to be broadly allocated according to the benefits accrued to each customer class.[3649] MNSC cite Ms. Davis's cross-examination testimony to argue that AMI meters provide benefits beyond basic metering functions.[3650] They further argue that the Company has already quantified the demand and energy benefits of AMI in its business case, which suggests that the benefits are not hypothetical as argued by Mr. Robertson.[3651] MNSC state that past reliance on the weighted customer allocator to apportion metering costs does not imply that the allocation of AMI costs has been

---

[3646] 5 Tr 407-410.
[3647] Consumers brief, 450.
[3648] MNSC brief, 89-91.
[3649] MNSC brief, 91, citing June 19, 1995 order in Case No. U-10554, pp. 20-21 and July 2, 2024 order in Case No. U-21461, pp. 66-71.
[3650] MNSC brief, 93.
[3651] MNSC brief, 94.

contested and approved by the Commission.[3652] MNSC also argue in support of Ms. Palmer's proposal that the Company continue producing its AMI business case benefit analysis because it will ensure continued transparency about the impacts of AMI for all customer classes.[3653]

In reply, Consumers refutes MNSC's claim that federal and state law require AMI costs to be allocated according to program benefits.[3654] Regarding federal authority, Consumers states that the Commission is not required to conform Michigan ratemaking to federal decisions about the application of cost-causation principles.[3655] It argues that federal courts have held that the cost-causation principle "traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them."[3656] Consumers states that while the U.S. Court of appeals has adopted a methodology of comparing costs assessed against the burdens imposed or benefits drawn by a party, the Court was only adopting a deferential standard for guiding its own post hoc review of FERC's cost allocation decisions.[3657] The Company further states that federal courts will regard FERC's allocation of costs as arbitrary and capricious when the customer does not experience sufficient benefits from the cost, but this does not support the proposition that FERC must assign costs to a customer if there is any conceivable benefit.[3658]

[3652] MNSC brief, 94-95.
[3653] MNSC brief, 95.
[3654] Consumers reply, 23.
[3655] Consumers reply, 23.
[3656] Consumers reply, 23, quoting *K N Energy, Inc v FERC*, 968 F2d 1295, 1300; 297 US APP DC 13 (1992).
[3657] Consumers reply, 24, citing *Midwest ISO Transmission Owners v FERC*, 373 F3d 1361, 1368; 362 US APP DC 314 (2004).
[3658] Consumers reply, 24, citing *Paragould Light & Water Comm v FERC*, 144 F4th 287, 292 (DC Cir, 2025).

In discussing FERC Order 1000 (establishing principles for evaluating a transmission owner's proposed cost allocation formula), Consumers argues that FERC's focus remains cost causation.[3659] While FERC requires that costs be allocated in a manner that is commensurate with estimated benefits, it clarified that this was consistent with its view of determining cost-causation principles, which asks "whether a proposal fairly assigns costs among those who cause the costs to be incurred and those who otherwise benefit from them."[3660] Consumers also states that FERC made clear it did not intend to embrace every conceivable form of benefits as adequate to support a cost allocation proposal.[3661] The Company argues that the benefits MNSC claims customers receive from AMI investments are indirect benefits and are not the type of benefits that are typically treated as relevant for cost allocation purposes.[3662]

Regarding Commission precedent, Consumers disputes MNSC's claim that Case No. U-10554 supports a benefits-based allocation of costs. It argues that in that case, while the Commission found that a Demand Side Management program would "benefit all customers," the Commission also viewed the cost causation for Demand Side Management programs the same way it views cost causation for new power plants, that is, all customers cause those costs, so all customers should be allocated a portion of the costs.[3663] The Company also notes that the Commission explicitly stated in Case No. U-10554 that "the costs of [Demand Side Management] are not allocated based

---

[3659] Consumers reply, 25, citing 136 FERC 61051 (2011).
[3660] Consumers reply, 25, citing 136 FERC 61051 at ¶ 622.
[3661] Consumers reply, 26.
[3662] Consumers reply, 27.
[3663] Consumers reply, 27-28, quoting June 19, 1995 order in Case No. U-10554, p. 13.

upon the benefits that customers receive."[3664] It adds that in another case involving cost allocation for power plants, the Commission made clear that it "continues to view cost allocation in accordance with cost causation principles."[3665]

MNSC argue in support of Ms. Palmer's proposed alternative cost allocator based on the projected benefits of the Smart Grid program, stating that AMI is an indispensable part of that program, and without AMI the Company likely cannot realize the energy-related and demand-related benefits that Ms. Palmer included in her proposal. They assert that even if all benefits stemming from the Smart Grid program cannot be attributed to AMI, it does not mean that Ms. Palmer's cost allocator is flawed, adding that Ms. Palmer's testimony relies on Consumers' findings that smart grid benefits are 17% demand-related and 36% energy-related, and there is nothing to suggest that the benefits of AMI differ in nature or proportion to the benefits of the Smart Grid program overall.[3666]

MNSC also argue that while the benefits of AMI accrue to the customers and classes that use it, the benefits are also shared with the customers and classes that do not. They state that AMI helps mitigate the need for new generation and transmission infrastructure, avoiding costs that would otherwise be imposed on all customers, and, because all customers benefit from AMI, it is only equitable that all customers should pay for its costs.[3667]

In its reply brief, ABATE disputes MNSC's interpretation of MCL 460.11 as supporting a benefits-focused allocation method and argues that the statute is not

---

[3664] Consumers reply, 27-28, quoting June 19, 1995 order in Case No. U-10554, p. 14.
[3665] Consumers reply, 28, quoting June 7, 2012 order in Case No. U-16794, p. 107.
[3666] MNSC reply, 9.
[3667] MNSC reply, 10.

subject to modification based on irrelevant and nonprecedential federal caselaw or decisions from alternative commissions.[3668] ABATE argues that the order in Case No. U-10554 was issued prior to the enactment of MCL 460.11 and is contradicted by *Attorney General v Pub Serv Comm'n*, 269 Mich App 473, 481 (2005), where the Court of Appeals held that the Commission did not have the authority to compel customers to support a program if they did not choose to receive power from the program, regardless of potential benefits.[3669] It also states that in Case No. U-21461 (cited by MNSC), the Commission did not allocate DERMS costs to all customers but instead found that the issue of cost allocation would be better addressed in an ongoing workgroup.[3670] In addition, ABATE cites authority to support its assertion that the Commission and the Court of Appeals have already determined that costs related to AMI are customer-related and should be allocated accordingly.[3671] It further argues that if the Commission were to allocate costs based on benefits, the purported benefits identified by MNSC do not provide a basis for doing so.[3672]

As an initial matter, this PFD finds that costs associated with meters have traditionally been classified as customer-related, and the Commission has consistently applied Consumers' weighted customer allocator to apportion the costs of AMI meters.[3673] As MNSC propose changing this established method of allocating these costs, they carry the burden of showing that their proposed alternative method better

---

[3668] ABATE reply, 23-24.
[3669] ABATE reply, 24.
[3670] ABATE reply, 24, citing July 2, 2024 order in Case No. U-21461.
[3671] ABATE reply, 24-25.
[3672] ABATE reply, 25-26.
[3673] 4 Tr 2672-2673; 6 Tr 3827; MNSC brief, 94-95.

ensures that rates are equal to the cost of service.[3674] For the reasons stated below, this PFD concludes that MNSC failed to meet their burden.

This PFD disagrees with MNSC's contention that Michigan law requires AMI costs to be allocated according to program benefits. To start, MCL 460.11(1) states:

> [T]he commission shall ensure the establishment of electric rates equal to the cost of providing service to each customer class. In establishing cost of service rates, the commission shall ensure that each class, or sub-class, is assessed for its fair and equitable use of the electric grid. . . . The commission shall ensure that the cost of providing service to each customer class is based on the allocation of production-related costs based on using the 75-0-25 method of cost allocation and transmission costs based on using the 100% demand method of cost allocation. The commission may modify this method if it determines that this method of cost allocation does not ensure that rates are equal to the cost of service.

There is no explicit requirement in this statute requiring costs to be allocated based on benefits. And while the statute provides default methods for allocating transmission and production-related costs, it establishes no preferred method for allocating other asset classes, including meters. A statute that is clear and unambiguous must be applied as written, and a requirement must not be read into an unambiguous statute where none appears in the plain language.[3675]

This PFD also finds that MNSC have fallen short of showing that the Commission requires "utility costs to be broadly allocated according to the benefits accrued to each customer class."[3676] While MNSC cite two cases where the Commission addressed the benefits of a program in the context of allocating costs, these cases do not establish

---

[3674] June 15, 2015 order in Case No. U-17689, pp. 18-19.
[3675] *Nickola v MIC Gen Ins Co*, 500 Mich 115, 123, 125; 894 NW2d 552 (2017).
[3676] MNSC brief, 91.

that the Commission has adopted a benefits-centered approach to cost allocation.[3677] This PFD instead finds that the Commission has historically followed traditional cost-causation principles.[3678]

Next, this PFD shares several concerns expressed by the Company and intervenors regarding MNSC's allocation method proposed in this case. MNSC's method would assign 22% of AMI meter costs to primary rate customers even though just 0.04% of AMI meters serve that customer class. Allocating meter costs to a class of customers that does not use the meters—meaning it does not cause the cost—would appear to contravene the mandates in MCL 460.11(1) that electric rates must equal "the cost of providing service to each customer class" and that the Commission "shall ensure that each class, or sub-class, is assessed for its fair and equitable use of the electric grid." In addition, as argued by Kroger, this PFD questions the accuracy of equating projected benefits of the entire smart grid program with avoided costs that can be expected from investments in AMI meters.[3679] In contrast to the current method, allocating costs based on inexact estimates imposes imprecision into the process that could lead to inequitable results. Finally, Consumers raised other legitimate concerns that MNSC's method is oversimplified because it assumes that the benefits from AMI

[3677] See MNSC brief, 91. This PFD agrees with the Company's and ABATE's analyses regarding these two cases. See Consumers reply, 27-28; ABATE reply, 24.

[3678] See, e.g., March 29, 2018 order in Case No. U-18322, p. 99 ("[T]he Commission finds persuasive MEC/NRDC/SC's and the Staff's recommendation that the allocation of distribution system costs should properly reflect the manner in which costs are caused."); June 15, 2015 order in Case No. U-17689, pp. 26-27 ("A principle of cost allocation is that costs that are directly attributable to a particular customer or class of customer should be directly assigned to that customer or class. [U]ncollectibles expense is an example of a customer-related cost that may be directly assigned to the class that is responsible. . . . It is appropriate and consistent with regulatory ratemaking principles to directly assign such costs to the class that caused the costs."); June 7, 2012 order in Case No. U-16794, p. 107 ("The Commission continues to review cost allocation in accordance with cost causation principles.").

[3679] See 5 Tr 3416-3419; Kroger brief, 3.

energy conservation accrue to all customers based on energy use and because it fails to consider the cost of non-AMI meters when calculating the benefits of AMI meters.[3680]

In the end, MNSC do not establish that the Company's method of allocating AMI meter costs fails to align with accepted cost-of-service principles or is otherwise unreasonable, nor do they propose a superior alternative method. This PFD also finds that Consumers should not be required to resume the filing of an updated AMI business case for the reasons expressed by the Company.[3681]

3. MAOAM Cost Allocation

Ms. Palmer opined that it is not reasonable to allocate MAOAM costs to all customers. She testified that while the Company justifies its allocation by stating that the project will support customers across various rate classes, the Company has not demonstrated that all classes will use the software proportionally to the proposed cost allocator. She stated that although all customers might have the ability to manage multiple accounts through a single login, it is unclear that the residential class requires such functionality. She added there are no customers with MAOAM login for multiple accounts because the tool is still in development, and only C&I customers have access to and use the current tool.[3682] Nevertheless, the Company proposes to allocate the majority (62.7%) of $0.64 million in MAOAM plant and expense to residential customers.[3683] Ms. Palmer therefore recommended that Consumers continue to break

[3680] 4 Tr 2673-2674; Consumers brief, 408-409.
[3681] Consumers brief, 450.
[3682] 6 Tr 3923.
[3683] 6 Tr 3923-3924, Table 2 at 6 Tr 3924.

out this project cost in the COSS and allocate it to the customer classes who use the program, based on the proportion of customers that have multiple logins.[3684]

Ms. Davis responded that the Company was previously ordered to break out MAOAM costs because the tool was only going to be available to C&I customers, which is no longer the case.[3685] She added that the Company currently uses a third-party tool that is only available to C&I customers, which does not reflect future utilization of the MAOAM tool.[3686]

Ms. Davis testified that approximately 115,000 residential customers have multiple accounts and could use the MAOAM tool compared to approximately 40,000 C&I customers, while around 50,000 customers manage a combination of residential and C&I accounts.[3687] She stated that 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.[3688] Ms. Davis testified that while Ms. Palmer may maintain the importance of doing a MAOAM study in future rate cases to account for that difference, precision needs to be considered in the context of the benefit and cost of providing that detail.[3689] She added that allocating 62.7% of the $0.30 million of test-year costs associated with the MAOAM project to residential customers amounts to $0.19 million compared to $0.17 million using the 56.2% figure. She concluded that filing a study in

---

[3684] 6 Tr 3924.
[3685] 4 Tr 2675.
[3686] 4 Tr 2674.
[3687] 4 Tr 2674.
[3688] 4 Tr 2674-2675.
[3689] 4 Tr 2675.

every rate case for a project that has a 1/10,000 of a penny impact on residential rates does not warrant the resources to do that study and sets an unrealistic precedent for future projects.[3690]

In its initial brief, MNSC argue that while the MAOAM tool may be made available to all customers in the future, that is not the case now.[3691] Until then, MNSC propose that costs should be allocated to C&I customers because they are currently the only customers who can or do use it.[3692]

This PFD finds Consumers' allocation method to be reasonable. Whereas the Commission previously required costs to be broken out for the C&I Online Account Management project because that tool was only available to C&I customers, the MAOAM tool will be available to all customers. Consumers has shown that a significant number of residential customers have multiple accounts, and there is no reason to believe this customer class will not utilize the MAOAM tool once it is available. Therefore, MNSC's proposal to allocate all MAOAM costs to C&I customers simply because the current tool is available only to those customers should be rejected. This PFD also agrees with Consumers that it would not be prudent to expend resources in an effort to more precisely allocate costs for this project.

B. Rate Design

Rate design refers to the framework to set prices and standards for the reliable provision of electricity services.

[3690] 4 Tr 2675.
[3691] MNSC brief, 86-87.
[3692] MNSC brief, 87.

Ms. Connolly testified that Consumers' proposed rate design is informed by four objectives: 1) adherence to the cost of service as required by MCL 460.11; 2) setting rates that encourage the efficient use of the Company's electric system; 3) setting rates that promote a favorable business climate; and 4) setting stable rates that provide Consumers with a fair opportunity to collect its revenue requirement.[3693]

According to Ms. Connolly, while MCL 460.11 requires electric utilities to design rates that reflect the cost of providing service to each customer class, utilities can still make adjustments that deviate from the COSS in some instances.[3694] She described six deviations or adjustments to the class COSS that she is recommending in this rate case and asserted that they are consistent with prior electric rate cases.[3695]

Ms. Connolly described her approach to designing rates to collect production costs. She explained that production is comprised of both fixed and variable costs, which are separated in the COSS between capacity, which represents the cost of maintaining generation plants, and energy, which represents the fuel and other costs of running the plants.[3696] She asserted that Consumers is using the weighted average hourly LMP to calculate the energy charge spreads for the various TOU rates, which is the same method used in Case No. U-21585.[3697]

Consumers maintains that its base rates are designed to recover its test year revenue requirement as well as the LTILRR revenues.[3698] Consumers further states that

---

[3693] 3 Tr 152-153.
[3694] 3 Tr 153.
[3695] 3 Tr 153-154; Ex. A-16, Sch. F-2.1.
[3696] 3 Tr 155.
[3697] Id.
[3698] Consumers initial brief, p. 413; Ex. A-16, Sch. F-2.0 and Conf. Ex. A-69.

the present and proposed electric charges were applied to the billing determinants to calculate the test year revenues.[3699]

Staff witness Todd testified that Staff corrected an error identified by Consumers in its voltage level calculation for class GSG-2 Standy-Service Production.[3700] Otherwise he testified that Staff reviewed Consumers' proposed rates upon completion of Staff's rate design and evaluated their consistency with general principles of rate design such as stability, efficiency, and reasonability[3701] Consumers does not refute Mr. Todd's testimony and requests that the Commission approve the Company's as-filed rate design with the modification to correct the voltage level calculation for the class GSG-2 Standby-Service.[3702] Ms. Connolly discussed the LTILRR but made no recommended changes to the rate.[3703]

She asserted that Consumers is proposing to maintain the currently approved residential rate design structure to provide a sense of stability for residential customers.[3704] She testified that the average monthly residential customer bill is projected to increase 11% from approximately $132 per month to $146 per month, which is $8 less than EIA's projected national average residential bill for 2026.[3705]

Consumers' proposal to continue the residential customer charge at $8.00 per month was uncontested, while Mr. Kelly discussed Consumers' proposal to update the

---

[3699] Consumers initial brief, p. 413; Ex. A-16, Sch. F-2.1.
[3700] 6 Tr 4595.
[3701] 6 Tr 4595-4596; Ex. S-6.
[3702] Consumers initial brief, p. 413.
[3703] 3 Tr 155-156.
[3704] 3 Tr 157.
[3705] 3 Tr 157-158; Ex. A-16, Sched. F-4.0.

Residential Smart Meter Opt-Out fee.[3706] Otherwise, Ms. Connolly asserted that Consumers recommends maintaining the currently approved secondary rate design structure, as well as the rate structure for Primary Rates GP, GPD, GPTU, and EIP.[3707] Ms. Connolly's recommended changes to the large economic development rate are discussed below.

1. Large Economic Development Rate

Ms. Connolly testified that Consumers is proposing three changes to its Large Economic Development Rate (LEDR or Rate LED): 1) updating the production capacity charge to the latest forecast of MISO Cost of New Entry (CONE); 2) including a facilities allowance; and 3) including a power factor adjustment.[3708]

As for the facilities allowance, Ms. Connolly testified that ever since the LEDR was established in 2021, customers have inquired about the availability of a facilities allowance that is like the allowance DTE offers to large customers in its Rate D13. She asserted that Consumers is proposing to add language offering such an allowance. She testified that the Company proposes calculating the facilities allowance based on the NPV of margin—defined as the non-energy related costs—based on each customer's expected load over five years of the contract term.[3709] She added that the proposal addresses the Commission's recommendation in Consumers' last electric rate case (Case No. U-21585) where the Commission stated that:

> in its next electric rate case, if the company believes it beneficial to provide a facilities allowance for Rate LED, Consumers should propose a facilities allowance that includes only distribution and system contribution

[3706] 3 Tr 158; Consumers initial brief, p. 419; Ex. A-16, Sch. F-3.0.
[3707] 2 Tr 157-159.
[3708] 3 Tr 159.
[3709] Id.

revenues, not power supply revenues, and that is based on a limited term.[3710]

She explained that Consumers believes that five years is an appropriate length of time to use in the calculation of the allowance because it corresponds to the standard Contribution in Aid of Constructure Allowance (CIAC) offered to primary customers.[3711]

Ms. Connolly testified that Consumers is also proposing to add an adjustment for power factor to LEDR that mirrors the design of the recently approved adjustment for Rates GP, GPD, GPTU, and EIP, except the Company proposes to assess penalties to LEDR customers for power factors between 0.700 and 0.909.[3712] She explained that the Distribution-Transmission Interconnection Agreement (DTIA) Consumers maintains with METC requires the Company to maintain an average power factor of 0.98 or better across all interconnection points at system load levels above 90% of peak. Since LEDR customers can significantly impact the Company's total system power factor, Consumers is proposing that they be held to a higher power factor standard.[3713]

ABATE witness Dauphinais found it appropriate for Consumers to update the LEDR production capacity charge to reflect the latest available MISO CONE.[3714] He also testified that ABATE supports the addition of a facilities allowance to LEDR, but he emphasized that ABATE only supports the proposal to the extent the sale margins used in determining the allowance are limited to the expected system contribution and delivery service revenues of the customer.[3715]

[3710] 2 Tr 160, citing Case No. U-21585 Order, March 21, 2025, p. 424-425.
[3711] 2 Tr 160.
[3712] Id.
[3713] 2 Tr 160-161.
[3714] 6 Tr 3652.
[3715] 6 Tr 3652-3653.

As for the power factor proposal, Mr. Dauphinais testified that ABATE opposes the use of a 0.909 power factor threshold for LEDR. He asserted that LEDR customers pay the same delivery service charges as customers under Rates GP, GPD, GPTU, and EIP, and therefore should have the same power factor provisions as those rates.[3716] He testified that the Company provided no evidence in its direct testimony to support that existing or potential LEDR customers, either alone or in aggregate, threaten its ability to comply with the DTIA, or that the application of power factor provisions combined with delivery charges would not provide sufficient contribution from LEDR customers to cover the cost of power factor correction on Consumers' system.[3717] He explained that larger customers would have higher demand and a higher level of kVAR deviation for the same amount of power factor deviation, meaning that for the same level of power factor deviation, these customers will pay higher delivery service charges and higher per kVAR charges than a smaller customer. He also pointed out that there is no evidence that LEDR load would be as significant as new data center load, and yet Consumers did not include a similar 0.909 power factor threshold in its proposed data center amendments in Case No. U-21859.[3718]

Solar Technology witness Gorman also opposed Consumers' power factor proposal for LEDR customers, stating that Consumers did not support the need for a more restrictive threshold.[3719] He asserted that using the same power factor provision for LEDR customers as for customers under rates GP, GPD, GPTU and EIP will ensure

---

[3716] 6 Tr 3655.
[3717] 6 Tr 3656.
[3718] 6 Tr 3656-3657.
[3719] 4 Tr 2927.

that rates reflect Consumers' cost of providing service and that all customers are treated fairly.[3720]

Mr. Gorman stated that Consumers' proposal is discriminatory because LEDR customers would pay a higher cost for the delivery of the same proportion of kWs and kVARs than other customers would. He explained that if Rate LED and Rate GP/GPD/GPTU/EIP customers have the same power factor, then Consumers needs to generate and deliver the same kVARs for each kW billing unit and if the power factor penalties and credits are the same across rate classes, then customers in all classes are treated fairly, and pay charges that align with Consumers' cost of service.[3721]

Mr. Gorman maintained that a large LEDR customer should not pose a risk to Consumers DTIA compliance. He noted that the Company's discovery responses indicated that its power factor would be well within the DTIA requirement of 0.98 and not result in any penalty if it added a new 50 MW LEDR customer that operates at 80% or 85% Power Factor.[3722]

MNSC witness Palmer expressed concerns that Consumers' facilities allowance proposal for LEDR customers would increase costs for other customers and contradict Michigan law.[3723] She explained that a facilities allowance could increase costs for other customers if the revenues paid by the LEDR customer do not fully offset the incremental distribution costs of serving the customer, such as dedicated infrastructure and marginal costs. She asserted that these costs are typically recovered through the customer's "incremental" distribution charge, which the proposed facilities allowance would

[3720] 4 Tr 2922.
[3721] 4 Tr 2928-2929.
[3722] 4 Tr 2929-2930; Ex. SLT-2 and SLT-3.
[3723] 6 Tr 3931.

reduce.[3724] She testified that Consumers acknowledged in discovery that it has not calculated its marginal distribution cost and therefore she posited that the Company cannot demonstrate that LEDR with an applied facilities allowance would fully cover the LEDR customer's incremental costs.[3725] She maintained that until Consumers can demonstrate that the LEDR customer will pay all of its marginal distribution costs and not increase costs to other customers, the Commission must reject the Company's facilities allowance proposal.[3726]

In the event the Commission approves the facilities allowance for LEDR, Ms. Palmer opposed its retroactive application. She testified that customers are offered the LEDR based on the investment and jobs they would bring to Consumers' territory and applying a facilities allowance to existing LEDR customers would make them "free-riders" who would receive a discount despite it playing no part in their decision where to locate.[3727] She further testified that considering Consumers' test year forecast for LEDR capacity and energy, the costs to apply the facilities allowance retroactively would be significant and would reduce the Company's LEDR revenues below marginal costs. She opined that it is completely unnecessary to apply the facilities allowance retroactively, given that existing LEDR customers have already made the decision to site their operations in Consumers' service territory.[3728]

Ms. Palmer also expressed concern that Consumers is not proposing to true up the facilities allowance. She recommended that if the Commission approves a facilities

---

[3724] 6 Tr 3931-3932.
[3725] 6 Tr 3931-3932; Ex. MEC-21.
[3726] 6 Tr 3932.
[3727] 6 Tr 3933.
[3728] 6 Tr 3934.

allowance, that after Consumers has collected five years of revenue, the Company should reconcile any overestimated revenue upon which it originally based the facilities allowance.[3729]

Next, Ms. Palmer recommended that Consumers increase the LEDR system contribution charge. She explained that the system contribution charge is intended to ensure that Consumers' other customers benefit from the LEDR customer's contract by having the LEDR customer contribute to Consumers' embedded costs of capacity. She testified that the current system contribution charge was set in 2020 based on 1% of the Rate GPD embedded capacity costs approved in Case No. U-20697, and it has not been updated since.[3730] She indicated that Consumers did not base the charge on any assessment of Rate LED's embedded cost or other analytical justification, but it was just the most it could ask LEDR customers to pay. She recommended that Consumers raise the charge to contribute more meaningfully to embedded system costs.[3731]

Ms. Palmer lastly recommended that Consumers shorten the LEDR discount period, which is currently the full contract term of 15-20 years.[3732] She asserted that utilities in other states, including Kentucky, Virginia, Missouri, Kansas, Florida, Iowa, and South Carolina, offer discount rates for only five years, but customers must remain on the system for 10 years and if a customer departs before 10 years, it is liable for a proportion of the credits provided.[3733] She recommend that Consumers offer LEDR for a maximum of 7 years, which is the length of time Indiana Michigan Power provides its

---

[3729] 6 Tr 3934-3935.
[3730] 6 Tr 3935.
[3731] 6 Tr 3935-3936.
[3732] 6 Tr 3936.
[3733] 6 Tr 3936-3937.

economic development rate to Indiana customers. She asserted that Consumers should offer the discounted rate for a shorter time unless or until it can provide justification for a longer time period.[3734]

In rebuttal Ms. Connolly testified that after further review, the Company acknowledges that its request to apply a stricter power factor penalty upon LEDR customers may be premature. However, she testified that Consumers remains concerned that an extremely large customer could influence the Company's overall power factor.[3735]

Ms. Connolly countered Ms. Palmer's assertion that LEDR customers may not be paying their marginal distribution costs. She testified that the LEDR is not based on marginal distribution costs and LEDR customers pay the same distribution rates as other customers.[3736] She added that other similarly situated customers are afforded a CIAC allowance to cover some or all of their incremental distribution costs. She asserted that Ms. Palmer's recommendation to require Consumers to demonstrate that the LEDR customer will pay all its marginal distribution costs before approving the facilities allowance is flawed and inconsistent with the LEDR methodology approved by the Commission.[3737]

As for Ms. Palmer's opposition to retroactive application of the facilities allowance, Ms. Connolly testified that prior negotiations with existing LEDR customers often included the potential for a facilities allowance. She recommended that if the Commission approve the facilities allowance, it should be applied retroactively to

---

[3734] 6 Tr 3937.
[3735] 3 Tr 167.
[3736] 3 Tr 169.
[3737] Id.

customers with express language in their contract around the potential for the allowance.[3738]

In response to Ms. Palmer's true-up recommendation, Ms. Connolly testified that Consumers intends to reconcile any differences in actual collections to proposed collections as allowed by the LEDR tariff and would include the facilities allowance in those calculations.[3739]

As for Ms. Palmer's recommendation to raise the system contribution charge for LEDR customers, Ms. Connolly testified that it should be rejected. Ms. Connolly pointed out that Ms. Palmer did not provide an alternative to the current calculation other than to say it should be increased. Ms. Connolly recommended that any change to the system contribution charge should be consistent with the methodology used in Case No. U-21160.[3740]

Lastly, Ms. Connolly opposed the shortening of the LEDR contract period. She asserted that there is no discount associated with the LEDR, as it is based on cost of service, and characterizing the rate as a discount undermines the integrity of the Commission's review process and incorrectly implies that the Commission approved a rate that violates Michigan law. She testified further that a shortened contract length could potentially result in stranded assets if a customer decided to cease taking service from the Company at the end of a seven-year contract.[3741]

Mr. Dauphinais testified in rebuttal that Ms. Palmer provides no evidence to support her contention that there is a marginal distribution cost for Consumers to serve

---

[3738] 3 Tr 170.
[3739] Id.
[3740] 3 Tr 171.
[3741] 3 Tr 171-172.

a LEDR customer and therefore her testimony objecting to the facilities allowance is "purely theoretical and thus baseless."[3742] He testified further that she did not account for system contribution charge revenues, which are a source of sales margins from the LEDR customer that would not exist but for the customer taking service from Consumers.[3743]

As for Ms. Palmer's recommendation for a shorter LEDR discount term, Mr. Dauphinais maintained that Consumers should be provided sufficient leeway to prudently negotiate with a prospective LEDR customer to bring that customer to its service territory.[3744] He noted that LEDR customers pay the fully embedded costs of transmission and distribution service and it is only LEDR production charges that are not based on Consumers' fully embedded costs.[3745] Nonetheless, he maintained that LEDR production charges are designed to cover incremental production costs and ensure that other customers are not subsidizing the LEDR customer. And he pointed out that the LEDR customer would likely not even be a Consumers' customer but for the LEDR and its allowed term of up to 20 years.[3746]

Mr. Gorman rebutted Ms. Palmer's concerns that other customers could be harmed by the facilities allowance. He testified that the facilities allowance is specifically designed to protect Consumers' ability to recover its incremental costs from the LEDR customer: if Consumers' cost of interconnecting the new customer is more than the facilities allowance, then the Company can either increase the customer's distribution

---

[3742] 6 Tr 3667.
[3743] Id.
[3744] 6 Tr 3668.
[3745] 6 Tr 3668-3669.
[3746] 6 Tr 3669.

charges or require the customer to make a CIAC payment.[3747] He also countered Ms. Palmer's assertion that Consumers should demonstrate that the revenue it collects from the facilities allowance will be adequate to fund all dedicated facilities' costs. He opined that, "[i]t is likely that a large LEDR customer will have dedicated distribution facilities that will be directly connected to a bulk transmission system[ ] and will not be connected to Consumers common distribution network" and "incremental distribution cost should be limited only to the distribution capacity expansion of the distribution network that is needed to serve only the LEDR customer specifically."[3748] He maintained that to the extent Consumers is able to serve the LEDR customer from existing common distribution facilities without any upgrades, then Consumers will not incur incremental distribution costs.[3749] He asserted there will be no negative impact on existing customers and they will benefit from Consumers' having expanded billing units over which to recover existing distribution system cost.[3750]

Mr. Gorman opposed Ms. Palmer's recommendation to limit the facilities allowance to new customers. He asserted that it would be unreasonable to exclude existing LEDR customers since every other primary customer has an opportunity to utilize a facilities allowance and Consumers' incremental costs would be fully recovered. He maintained that while the existing LEDR customer should be able to take full advantage of the facilities allowance, if it is limited, the customer should at least be able

[3747] 4 Tr 3173-3176.
[3748] 4 Tr 3177.
[3749] Id.
[3750] 4 Tr 3177-3178.

to use it to the extent it has new load growth that requires further distribution investment. [3751]

Lastly, Mr. Gorman opposed Ms. Palmer's recommendations to adjust the system contribution charge and reduce the term of the existing LEDR contract. He asserted that she did not demonstrate "a reasoned basis for changing these previously Commission-approved provisions." However, he stated, if the Commission approves these changes, it should not impair any existing LEDR contracts as these should be honored.[3752]

Consumers', ABATE's, and Solar Technology's briefs largely track the testimony of their respective witnesses opposing MNSC's recommendations and discussing the purpose and importance of the facilities allowance for Rate LED. For instance, ABATE argues that the facilities allowance achieves the LEDR's purpose, which is to attract new load, while still ensuring that the incremental cost to serve the customer is covered and existing customers realize a benefit by the customer's additional contribution toward the Company's embedded costs.[3753]

In its brief, MNSC argues that a comparison of Rate LED to Rate GPD, as gleaned from its cross examination of Ms. Connolly, demonstrates that Rate LED is unreasonably and excessively discounted.[3754] MNSC contends that, "[r]esidential rates continue to escalate while the Company strives to give ever more discounts to large customers – even customers who are already signed – under the guise of economic

---

[3751] 4 Tr 3179.
[3752] 4 Tr 3180.
[3753] ABATE initial brief, p. 71-72.
[3754] MNSC initial brief, p. 97-100.

development."[3755] MNSC describes past PFDs and Commission orders where the Consumers' facilities allowance proposal for LEDR was rejected and maintains that it should be rejected again because: Consumers has not proven that dedicated and marginal distribution costs would be covered and costs would not increase for other customers; it is unnecessary since the LEDR is already excessively discounted, particularly if the customer elects interruptible service; the proposal is insufficiently developed; and Consumers has not supported its claim of economic development benefits.[3756]

MNSC counters the argument that Ms. Palmer did not support her contention that there would be a marginal distribution cost to serve the LEDR customer, stating that it is Consumers' burden to prove that the LEDR rate with a facilities allowance "would still be equal to the cost of providing service to each customer class, that the allowance is just and reasonable, and that no customer will be charged more or less than other consumers are charged for like contemporaneous service rendered under similar circumstances and conditions."[3757] MNSC further notes that only very large customers, with at least 35 MW of load, are eligible for the LEDR, such that "the notion that Consumers could add a customer with that level of demand without adding *any* marginal costs to the distribution system—any need for additional or larger equipment anywhere on the system—is not plausible."[3758]

MNSC also elaborates on Ms. Palmer's testimony opposing retroactive application of the facilities allowance and counters Ms. Connolly's rebuttal testimony

[3755] Id., p. 100-101.
[3756] Id., p. 102-112.
[3757] Id., p. 107.
[3758] Id., p. 108.

that the facilities allowance should be provided to existing customers with express language in their contracts. MNSC states that there are only two existing LEDR customers, one being Solar Technology, and their relevant contract language does not mention the facilities allowance or support Ms. Connolly's rebuttal.[3759] As for the need for a true-up, MNSC posits that it appears Consumers agrees to reconcile any overestimated revenues from the facilities allowance, if it is approved, but the Company does not indicate when, or often, any true-ups would occur. MNSC recommends that the Commission adopt its proposal for a five-year true-up.[3760]

Turning to MNSC's recommendations on other aspects of the LEDR, MNSC rejoins Consumers' rebuttal and states that the Company does not defend the size of the system contribution charge or argue that it is based on cost of service. MNSC agrees with Consumers that the system contribution charge can be updated based on the methodology in Case No. U-21160 and recommends further that it be updated in each case based on actual costs rather than locked in for the duration of an LEDR customer's contract.[3761] As for the contract term for LEDR customers, MNSC argues that Consumers' claim that the LEDR is not a discount rate is belied by the evidence and Consumers' concerns about stranded assets should be able to be addressed via the structure and terms of the relevant contract.[3762] MNSC also refutes Mr. Dauphinais' assertions about LEDR contract length, contending that they are unsupported and

[3759] Id., p. 113-116.
[3760] Id., p. 116-117.
[3761] Id., p. 117-119.
[3762] Id., p. 120-121.

wrongly claim that transmission charges are not discounted and that LEDR production charges are designed to fully cover incremental fixed and variable production costs.[3763]

In reply, Solar Technology argues that MNSC's claim that it is not plausible that Consumers could interconnect a 35 MW customer without adding any shared distribution investments indicates a lack of understanding of how large loads are served. Solar Technology argues that its witness, Mr. Gorman, has served as an energy regulatory expert for nearly 40 years, and it is typical that very large load customers are directly connected to the transmission system and that Consumers' investment in distribution infrastructure is limited to investment in a dedicated substation that is then directly connected to the transmission system.[3764]

Solar Technology also argues that MNSC's concerns regarding cost recovery in the unlikely event of an early termination of an LEDR contract appear to be based on a misunderstanding of the tariff provision. Solar Technology maintains that if a LEDR customer terminates service prior to its contract term, they must pay for the investments made to serve them and furthermore Consumers has indicated that it will reconcile or true up the customer's payments.[3765]

Solar Technology goes on to argue that Consumers has materially developed and narrowed its facilities allowance proposal since it was first introduced in Case No. U-21389 and the Company has fully supported how the proposal would promote economic development.[3766]

[3763] Id., P. 121-122.
[3764] Solar Technology reply brief, p. 7-8.
[3765] Id., p. 9-10.
[3766] Id., p. 10-11.

In its reply, ABATE contends that MNSC's comparison of the LEDR to Rate GPD is faulty, as Rate LED should be most similar to the LTILRR rate.[3767] According to ABATE, the Commission approved Rate LED over the same claims and arguments MNSC is making in this case.[3768] Now, years later, argues ABATE, "MNSC did not identify a single instance in which any of these claimed circumstances had any impact on other customers, or that the 'discounts' offered by Rate LED have increased customer rates."[3769] ABATE argues that MNSC's claims regarding production charges are an attempt to distract from the fact that Rate LED is cost of service based and does not result in customer subsidies.[3770] ABATE maintains that MNSC's objections to Consumers' Rate LED proposals are meritless and should be rejected.[3771]

Neither Consumers nor MNSC addressed the facilities allowance in their reply briefs.

As stated above, Consumers proposed three changes to the LEDR tariff. One of those changes, updating the production capacity charge to the latest forecast of MISO CONE, was supported by ABATE and was not opposed by any other party. As such this proposed change should be approved. The next proposed change, adding an adjustment for power factor that is equivalent to the adjustment recently approved for Rates GP, GPD, GPTU, and EIP, should also be approved. But the power factor provisions must be the same as those for other primary rates, that is, Consumers

[3767] ABATE reply brief, p. 12-13.
[3768] Id., p. 13, citing Case No. U-21160, Order, Dec. 2, 2021.
[3769] Id., p. 13-14.
[3770] Id., p. 14.
[3771] Id., p. 15.

should not apply a more restrictive power threshold, as the Company agreed with ABATE and Solar Technology and withdrew this part of its proposal.

As for the proposal to add a facilities allowance to LEDR, this was supported by ABATE and Solar Technology and opposed by MNSC. This PFD notes that in the Company's last two rate cases, its proposals to add a facilities allowance to LEDR were rejected by the Commission. Most recently, in Case No. U-21585, Consumers proposed a facilities allowance that included power supply costs and was based on the life of the LEDR customer contract. In that case, Staff opposed the proposal as structured, because including power supply costs would mean that LEDR customers do not contribute to embedded costs or make customers better off and using the entire term of the contract (up to 20 years) would erase any benefit of adding the new customer.[3772] The ALJ and the Commission agreed and the Commission expressly stated, "in its next electric rate case, if the company believes it beneficial to provide a facilities allowance for Rate LED, Consumers should propose a facilities allowance that includes only distribution and system contribution revenues, not power supply revenues, and that is based on a limited term, similar to DTE Electric's Rate D13."[3773]

This PFD finds that Consumers' current facilities allowance proposal is consistent with the Commission's order in Case No. U-21585 as it only includes distribution and system contribution revenues and is based on a limited 5-year term. Tellingly, Staff did not offer any testimony in opposition to the current proposal, which suggests that its concerns that the facilities allowance eliminates the benefits of the new LEDR customer

[3772] Case No. U-21585, Order, March 21, 2025, p. 415-416
[3773] Id., p. 424-425.

to other customers have been ameliorated. Therefore, this PFD recommends that the Commission approve a facilities allowance for LEDR that only includes distribution and system contribution revenues and is based on a limited 5-year term.

This PFD addresses MNSC's arguments. First, while MNSC is correct that the burden to support the facilities allowance falls on Consumers, this does not mean that Consumers must prove the opposite of every argument or speculation presented against its proposal. In this case, MNSC suggests that the proposed facilities allowance may increase costs for other customers or that the LEDR customer would not cover its marginal distribution costs, but MNSC does not provide sufficient evidence to show that these are valid concerns. Without this evidence it would be unreasonable and overly burdensome to approve a facilities allowance contingent upon the Company proving that MNSC is incorrect in its suppositions. MNSC's argument that LEDR customers already receive an excessively discounted rate is also insufficient as it does not provide evidence that the facilities allowance is unnecessary. Further, the argument that the proposal is not well-developed is belied by the analysis and testimony by the parties, the ALJ, and the Commission in this and previous rate cases. MNSC's final argument, that the Company has not provided evidence to support its claim of economic development benefits, is well-taken and was noted in the PFD in Case No. U-21585. However, the Commission did not find this issue dispositive when it rejected the facilities allowance in that case.

Turning to MNSC's four other recommendations, this PFD addresses them sequentially. First, this PFD agrees with the Company that the facilities allowance should be offered to an existing LEDR customer if the customer's contract contemplates

a future facilities allowance. However, in recognition of MNSC's contention that Consumers only has two existing LEDR customers and their contracts do not support retroactive application of the facilities allowance, this PFD recommends that if the Company intends to offer the facilities allowance to an existing LEDR customer that it first obtain approval from the Commission that the contract sufficiently contemplates the facilities allowance, and the Company may seek this approval ex parte. Second, since the Company indicated it would conduct a true-up and it did not oppose MNSC's recommendation to conduct the true up every five-years, this PFD recommends that the Commission require Consumers to reconcile any overestimated revenue upon which it originally based the facilities allowance every five years and charge the LEDR customer to make up any shortfalls. Third, this PFD finds it reasonable to update the systems contribution charge, finding that MNSC's argument was persuasive, Consumers did not provide opposing evidence, and the Company argued that any update should be consistent with Case No. U-21160. Therefore, this PFD recommends that the system contribution charge for LEDR customers should be updated in each rate case based on actual costs and using the methodology approved in Case No. U-21160. Finally, this PFD rejects MNSC's recommendation to shorten the LEDR contract period, finding persuasive the Company's argument that shorter terms increase the risk of stranded assets.

2. Data Centers

MNSC witness Palmer urged the Commission to require Consumers to analyze data center costs to ensure there is no rate subsidization. She opined that the riskiness and magnitude of infrastructure investment associated with potential new data centers

necessitates re-evaluating the traditional ways that Consumers would track and allocate costs.[3774]

She asserted that in Case No. U-21859, where Consumers proposed amendments to Rate GPD to serve data centers, she proposed a cost allocation method and Consumers responded that assigning costs was beyond the Company's proposal and more appropriate for a rate case.[3775] Ms. Palmer noted that Consumers indicated that it generally assigns costs when it expects to serve the relevant load in the test year.[3776] She testified that Consumers announced in August 2025 that it had an agreement to serve a data center with about 1 GW of load. She maintained that the load could possibly be operational in the 2026 test year and Consumers may soon begin to incur costs, making it essential that data center costs are proactively evaluated and assigned justly and reasonably.[3777]

Ms. Palmer testified further that MCL 205.54ee(10)(e)(x)(c) prohibits residential customers from subsidizing data centers, but in Case No. U-21859, the Company did not quantify or analyze data center costs, and yet it concluded "without evidence" that its proposed amendments to rate GPD would not increase the rates of other customers.[3778] She asserted that it is imperative that Consumers demonstrate compliance with MCL 205.54ee(10)(e)(x)(c) and she recommended that the

[3774] 6 Tr 3924.
[3775] 6 Tr 3925.
[3776] 6 Tr 3925-3926.
[3777] 6 Tr 3926.
[3778] 6 Tr 3927-3928.

Commission order Consumers to demonstrate in its next rate case that residential customers will not subsidize data centers.[3779]

Next, Ms. Palmer recommended that the Commission order Consumers to conduct sensitivity modeling runs in its next IRP with and without data center load of magnitudes that reasonably reflect Consumers' expected data center load at the time and to disclose the difference in revenue requirements and resource portfolios.[3780] She maintained that this analysis would help the Commission assess whether data centers pay their costs without subsidization from residential customers.[3781] She noted that in Case No. U-21859, Consumers indicated in discovery that load growth studies and decisions regarding the addition of new peak load and required generation supply would be included in the Company's 2026 IRP, but not specifically for data center load.[3782] She asserted that this would be a missed opportunity since with and without IRP modeling may be one of the best and only ways to evaluate the impacts of unprecedented data center load on Consumers' generation costs. She stated that she was aware of at least two other utilities, Dominion Virginia and Ameren Missouri, which have conducted IRP runs with and without data center load.[3783]

Ms. Connolly responded in rebuttal that the August 2025 agreement Ms. Palmer referenced was a Letter Agreement that addressed internal system studies and did not outline a load ramp schedule.[3784] She asserted that absent a signed rate contract for

---

[3779] 6 Tr 3927, 3928.
[3780] 6 Tr 3927.
[3781] 6 Tr 3928.
[3782] 6 Tr 3928-3929.
[3783] 6 Tr 3929.
[3784] 3 Tr 167.

test year service, it "would be premature to start making decisions about cost allocation in the instant case."[3785]

Ms. Connolly also testified that Ms. Palmer's recommendation that the Company demonstrate compliance with MCL 205.54ee(10)(e)(x)(c) in its next rate case is unnecessary as the Company must adhere to MCL 460.11, which requires that electric rates are equal to the cost of providing service to each customer class. She testified further that it was unnecessary that Consumers conduct sensitivity modeling runs in its IRP for data centers since the IRP already includes various sensitivities, including scenarios based on the probability of new load coming onto the system.[3786]

In its brief, Consumers points out that in Case No. U-21859, the Commission is requiring the Company to file at least six cost allocation and rate design proposals and provide them to the case's parties three months in advance of the Company's next rate case application.[3787] Consumers further argues that the Commission's U-21859 Order indicates that IRP matters should be addressed in Case No. U-21867 and in that case Staff has recommended modeling of incremental large load increases equal to 10% of the utility's annual forecasted load in years 2030, 2035, and 2040.[3788]

MNSC's brief agrees with the Company that the Commission largely addressed MNSC's recommendations concerning data center cost allocation in its Case No. U-21859 Order.[3789] MNSC maintains that while it is not "entirely satisfied" with the

---

[3785] 3 Tr 168.
[3786] Id.
[3787] Id., citing Case No. U-21859 Order, November 6, 2025, pages 115-116.
[3788] Consumers initial brief, p. 421, citing U-21859 Order, November 6, 2025, page 118.
[3789] MNSC initial brief, p. 87-88.

Commission's order, particularly directing data center modeling to Case No. U-21867, "the Commission has spoken on these issues for now."[3790]

Since the parties generally agree that the Commission has already addressed MNSC's recommendation that Consumers be required to demonstrate compliance with MCL 205.54ee(10)(e)(x)(c) and model data center load in its 2026 IRP, this PFD finds the issue moot and makes no recommendations.

C. Electric Vehicle Rate

Staff witness Krause testified that Consumers' Rate GP should be closed to EV fast charging customers. He asserted that charging stations on the rate are receiving a subsidy because the rate does not reflect their cost of service. He explained that under rate GP, charging stations are treated as if increasing charging speed has no incremental impact on cost causation, however as these stations increase in speed and demand, the GP rate becomes less and less appropriate. He testified that rate GP should be closed to both new and existing fast charging stations on June 1, 2028 and he noted that Staff made a similar proposal in DTE's rate case.[3791]

Mr. Krause testified that Staff is recommending that Consumers propose a new tariff for fast charging in its next rate case based on available data and cost-of-service. Further he testified that since there would likely be a preference for an energy-only rate with no demand charges, Staff would like to see this incorporated into the proposal. He also expressed Staff's recommendation that Consumers provide rate design options that consider charging station uptime and charging reliability.[3792]

[3790] Id., p. 88.
[3791] 6 Tr 4505.
[3792] 6 Tr 4505-4506.

Walmart witness Lyon testified that Consumers should offer a DCFC-specific rate that is volumetric and based on cost-of-service and which encourages investment for business customers who are interested in owning and operating public EV DCFC equipment and stations.[3793] He asserted that Walmart supports clean energy and carbon reduction goals and believes that building a strong public network of DC fast chargers is essential for supporting the EV industry.[3794] He maintained that a key factor in attracting third-party investment in charging stations is specific EV-friendly rate options.[3795]

Mr. Lyon testified that Walmart currently hosts more than 1,200 public DCFCs at 285 different locations across 43 states and intends to build its own EV fast-charging network across the U.S. over the next few years.[3796] He asserted that electric rates are a factor that Walmart considers when deciding where to site EV charging infrastructure.[3797] He testified that while the EV industry continues to grow, there will still be geographical locations where public EV chargers are under-utilized and if they are charged under a traditional rate tariff with a demand charge, they could be assessed the maximum demand charge even after only a single use. He maintained that this negatively impacts the economics for that charging unit and may lead to little or no third-party investment in public EV chargers sited in these geographical locations.[3798] He recommended that the Commission require the Company to work with interested parties to develop a new EV tariff that encourages investment specifically for third party-owned

---

[3793] 3 Tr 2620.
[3794] 3 Tr 2620-2622.
[3795] 3 Tr 2621.
[3796] Id.
[3797] 3 Tr 2622.
[3798] 3 Tr 2623.

public-facing EV DCFC stations and to seek Commission approval of such in its next general rate case.[3799]

In rebuttal, Ms. Connolly testified that Consumers has limited data on charging stations such that it would be premature to develop a DCFC cost-of-service rate. She explained that the Company is only able to identify fast charging customers which were rebated under the PowerMIDrive program, which she indicates is 84 customers. She added that Consumers does not know if it has the requisite three years of data for a COSS for these 84 customers, or even if it has one year of data. Furthermore, she stated, there is a potentially sizable number of DCFC customers which are not separately metered but are aggregated in a customer's total load.[3800]

Ms. Connolly maintained that in DTE Electric's last rate case, the Commission determined that it was premature to implement a COSS and rate design for DCFC based on limited data from 21 chargers of approximately 68 DCFC customers. She asserted that since Consumers' DCFC data is similarly constrained, the Company should not be directed to develop a COSS and rate design in its next case.[3801]

Ms. Connolly also rejected Mr. Krause's proposal to close Rate GP to new fast charging stations and move existing fast charging stations to the to-be-created DCFC tariff given the limited data she discussed above.[3802]

MEIU witness Schuster also provided rebuttal to Mr. Krause's testimony. She asserted that EV charging stations on Rate GP are not receiving a subsidy when considered in the context of EV-derived revenues in the aggregate. She explained that

---

[3799] 3 Tr 2623.
[3800] 3 Tr 172.
[3801] 3 Tr 172-173; Case No. U-21534, Order, Jan. 23, 2025, p. 426.
[3802] 3 Tr 173.

while DCFC are a key enabling technology for broad adoption of EVs, they currently have high costs, such that adding demand charges to those costs would erode EV adoption, which she maintained would in turn depress incremental revenue from EV charging.[3803] She stated that Mr. Lyon's testimony supports the view that demand charges could lead to little or no third-party investment in certain areas of low initial EV adoption. She testified further that billing DCFC with low utilization rates under a tariff with a demand charge is, in fact, likely to be overcharging on a cost-of-service basis.[3804]

As for Mr. Krause's recommendation to close Rate GP to all new and existing fast charging customers on June 1, 2028, she asserted that only when there are more DCFC across the state and their utilization rates increase and stabilize will it be appropriate to sunset the "demand charge holiday" and determine the suitability of a DCFC-specific tariff.[3805] She noted that she expects the network of DCFC stations across the state to expand significantly between 2026 and 2028 because of the National Electric Vehicle Infrastructure (NEVI) program and private initiatives such as the EVgo and Meijer partnership.[3806] She also asserted that prematurely implementing a sunset to the "demand charge holiday" by requiring DCFC customers to move off Rate GP could result in higher operating costs, thus deterring future DCFC development and private investment, which would reduce the amount of DCFC data available for a COSS assessment.[3807] In other words, she asserted, the opportunity for DCFC stations to remain on Rate GP more readily actualizes net benefits to all ratepayers and increases

[3803] 6 Tr 4180-4181.
[3804] 6 Tr 4181-4182.
[3805] 6 Tr 4183.
[3806] 6 Tr 4184-4185.
[3807] 6 Tr 4185-4186.

the amount of data available to the Company, thus ensuring a more reliable COSS.[3808] At minimum, she contended, the Commission should not establish a "demand charge holiday" sunset date until the Company has filed the findings of an accurate DCFC COSS and interested parties have had the opportunity to review and comment on it. Until then, she recommended that the Commission reject witness Krause's recommendations to remove new and existing DCFC customers from Rate GP on June 1, 2028.[3809]

Ms. Schuster emphasized that if the Commission were to adopt Mr. Krause's recommendation to close rate GP to both new and existing customers on June 1, 2028, a DCFC station in the Company's service territory energized on June 1, 2027 would only be able to enroll in Rate GP for one year. She opined that this would be inconsistent with the Commission's Order in Case No. U-21389, which allowed DCFC stations to remain on the "demand charge holiday" rate for two years.[3810] She therefore recommended that if the Commission determines that a concrete sunset date is absolutely necessary, the Commission should, at a minimum, maintain consistency and allow DCFC stations energized between June 1, 2026 and May 31, 2028 to remain on Rate GP for two years, irrespective of the demand charge waiver sunset.[3811]

Ms. Schuster testified further that Staff's recommendation that Consumers propose a DCFC-specific tariff in its next rate case should be rejected because it is premature based on the lack of data she described. She pointed out that in Case No. U-21585, Consumers' witness Myrom indicated that the limited number of DCFC sites and

[3808] 6 Tr 4186.
[3809] 6 Tr 4186-4187.
[3810] 6 Tr 4189-4190.
[3811] 6 Tr 4190.

low utilization rates in the Company's service territory was making it difficult to establish a reliable DCFC load shape on which to base a DCFC-specific tariff.[3812] She asserted that while the number of DCFC stations deployed has increased, it remains a small sample size, which makes any usage analysis sensitive to swings caused by individual customers.[3813] She recommended instead that the Commission require Consumers to conduct a comprehensive evaluation of DCFC tariff best practices from other jurisdictions, collaborate with other interested parties, as suggested by Mr. Lyon, and require the Company to present its findings and propose a long-term plan for the eventual implementation of an appropriate DCFC tariff by December 1, 2026, or some other reasonable date.[3814]

Consumers' and Walmart's briefs largely rely on the testimony of their respective witnesses regarding the need for a new EV tariff and the status of the demand charge holiday.

In its brief, Staff asserts that rebates are available for DCFC to address the capital expense and help with the return of investment.[3815] Staff pushes back on Ms. Schuster's suggestion that there is no subsidy for EV charging stations on Rate GP when considered in the aggregate, stating that this is "akin to saying industries hire people that are residential customers, therefore low industrial rates help utilities because more residential customers pay rates that lead to increased revenue in the aggregate."[3816] Staff argues that this line of thought should be rejected and each class

---

[3812] 6 Tr 4179-4180.
[3813] 6 Tr 4187-4188.
[3814] 6 Tr 4188-4189.
[3815] Staff initial brief, p. 158.
[3816] Id.

should be evaluated on its own merit, which means evaluating DC fast charging separately from at home charging.[3817] Staff also argues that if other states are examined for EV rate best practices, only those that have cost of service requirements like Michigan, should be considered. [3818]

As for the demand charge holiday, Staff agrees with the MEIU that the Commission should not sunset the "demand charge holiday" until the Company has filed the findings of an accurate DCFC COSS and interested parties have had the opportunity to review and comment on the study's findings, but Staff continues to believe that this filing and review should take place in the next rate case.[3819]

Staff argues that the idea that more time is needed to collect DCFC data before a DCFC rate is determined should be rejected. Staff notes that Consumers has proposed a data center rate based on "potential" data centers and while EV rates have been addressed in previous proceedings, as mentioned by Consumers, time has passed since those proceedings, and more time will pass before the next rate case.[3820] Staff notes that any tariff would still be subject to the typical cost allocation and rate design process that occurs in every rate case and terms and conditions could be altered *ex parte*.[3821] Staff also points out that the end of the demand charge holiday does not necessarily have to coincide with the implementation of a new fast-charging tariff as fast-charging customers could be moved from Rate GP to Rate GPD or Rate GPTU.

[3817] Id.
[3818] Id., p. 159.
[3819] Id.
[3820] Id., p. 160.
[3821] Id., p. 160-161.

Staff reiterates that rates should be based on cost of service and therefore the demand charge holiday should firmly sunset on June 1, 2028.[3822]

MEIU's brief largely tracks Ms. Schuster's testimony. As for the sunset of the demand charge holiday, MEIU argues that in its order in Case No. U-21389, the Commission expressed a willingness to move the sunset contingent with the design of an EV rate:

> "[t]he Commission expects that consideration of the merits of a separate tariff for DCFCs will likely involve consideration of the ongoing need for a demand charge holiday beyond June 1, 2026. If the study of a DCFC tariff supports extending this deadline, Consumers may file for approval of such an extension in a future rate case."[3823]

MEIU argues that since the Company is not much closer to developing a DCFC-specific rate than it was in Case No. U-21389, the Commission should push back the Rate GP sunset date in accordance with what was foreshadowed in the order in U-21389.[3824] MEIU argues that it is crucial that the Commission extend the demand charge holiday sunset in this case since under current terms, DCFCs energized before June 1, 2024 will lose access to Rate GP on June 1, 2026, which is only a few months after the Commission's order is due in this case.[3825]

Staff's reply brief contends that MEIU's initial brief included non-record evidence, Staff's testimony from Case No. U-21389, that should be disregarded.[3826] Staff argues further that its previous support for an extension of the demand charge holiday was due to circumstances existing at that time, e.g. the pandemic, and it should "in no way be

---

[3822] Id., p. 161.
[3823] MEIU initial brief, p. 24-25, citing Case No. U-21389, Order, March 1, 2024, p. 114.
[3824] MEIU initial brief, p. 25.
[3825] Id., p. 25-26.
[3826] Staff reply brief, p. 12-13.

considered as support for continuing the demand charge holiday beyond June 1, 2028."[3827] Staff also disagrees with MEIU's suggestion that facts on the ground have not changed, noting that there is an additional 21 months of fast charging data available today than was available on March 1, 2024 when the order in Case No. U-21389 was issued. Staff reiterates that there is more than enough data to support proposing a fast-charging rate in the next rate case.[3828]

In its reply, MEIU addresses Staff's analogy to industrial rates and residential customers in response to Ms. Schuster's argument there is no subsidy for EV charging stations when considered in the aggregate. MEIU contends that Staff's analogy is unconvincing because:

> In the Staff's analogy, the industrial and residential rates under discussion are driven by load that is unique to the industrial and residential customers, respectively, without overlap. In the case of EVs, by contrast, the mobile nature of the load means that in many instances the same customer and even the same physical load (i.e., the vehicle) is pulling kWh off the grid at multiple different places, including at home or out in public at a DCFC station. Although the customer name on the utility bill in each location may be different, the end-use customer ultimately paying for the power is the same.[3829]

MEIU adds that because there is no clear subsidy to EV customers under Rate GP, there is no urgency to develop an alternative DCFC-specific rate in the next rate case, rather contends MEIU "the Commission should order the Company to engage in a thorough investigation of rates, engage in meaningful stakeholder outreach, and present its findings by a 'reasonable later date.'"[3830]

[3827] Id.
[3828] Id., p. 13.
[3829] MEIU reply brief, p. 4-5.
[3830] Id., p. 5-6.

It appears that no party opposed Staff's recommendation that a DCFC cost-of-service rate be developed, that it incorporates an energy only rate, or that Consumers provide rate design options that consider charging station uptime and charging reliability. However, the parties disagree on a timeline for the tariff proposal. Staff and Walmart argue, for different reasons, that Consumers should present the proposal in its next rate case, while Consumers and MEIU contend that that Consumers' next rate case is too premature. Finding MEIU's and Consumers' contentions that there is insufficient data to develop an accurate COSS and rate design for DCFC, this PFD recommends that the Commission direct Consumers to convene a work group, including Staff and interested parties, as soon as possible and develop a consensus-based EV fast charging rate proposal that is based on cost of service and which considers an energy-only rate, charging uptime, and charging reliability, and that encourages third-party investment if possible within the cost-of-service framework, and present it to the Commission no later than January 31, 2027.

Turning to Staff's recommendation to firmly sunset the demand charge holiday and close rate GP to both new and existing fast charging stations on June 1, 2028, this PFD agrees with Staff that rate GP may provide a subsidy to some EV charging stations. Nonetheless, this PFD agrees with the Company and MNSC that it is premature to end the demand charge holiday, finding that it would be inconsistent with the Commission's order in Case No. U-21389, which indicated that there may be a continuing need for the holiday and that Consumers may request an extension to the sunset. However, this PFD does not find it necessary, at this time, to extend the holiday beyond the June 1, 2028 date, given the recommendation that a new EV charging rate

be developed by January 31, 2027. Additionally, this PFD does not recommend removing the ability of new EV charging customers to stay on Rate GP for 2 years even if it extends beyond the June 1, 2028 sunset date.

D. Heat Pump Rate

MNSC witness Reeves provided extensive testimony in support of a special electric heat or heat pump (EH/HP) rate design. Mr. Reeves asserted that current rate structures discourage electrification and an EH/HP rate design is needed to promote electrification and achieve state climate goals.[3831]

Mr. Reeves testified that climate research indicates that reducing greenhouse gas emissions through building end uses, such as space and water heating, is critical to meeting climate goals. He indicated that while the magnitude of savings that could or should come from the building sector is debatable, some amount of decarbonization through electrification of building end-use loads will be necessary.[3832] And he maintained that many Michigan policies support electrification to achieve decarbonization goals. He noted, for example, that the MI Healthy Climate Plan promotes heat pumps in the near term to displace oil, propane, and natural gas and facilitate its goal that 17% of emissions reductions to meet its 2030 goals should occur through buildings.[3833]

He asserted that currently, customers who switch to electrically sourced heat will see increased electric bills in the winter, and if they are switching from natural gas to

[3831] 6 Tr 3844-3845.
[3832] 6 Tr 3860-3861.
[3833] 6 Tr 3846, 3858, 3861.

electric, they will likely have increased per unit heating costs.[3834] He presented data showing that the annual costs to heat a typical residential home using electricity exceed $1000, approximately twice that of annual gas heating costs.[3835] He testified that studies by the American Council for an Energy-Efficient Economy (ACEEE) and the Energy Systems Integration Group (ESIG) also find that the net increase in electric space heating increased average energy bills compared to gas heating bills.[3836]

He explained that under Consumers' current residential rate design, customers who use electricity to heat their homes in the winter pay on-peak summer system costs even though their heating usage is not contributing to the summer peak demand. He also suggested that these customers pay a higher portion of fixed system costs compared to non-electrified customers.[3837] He described this as an "inverse cost shift" effect where, under standard electric rates with volumetric pricing aimed at recovering portions of both fixed infrastructure costs and variable costs, heat pump customers end up paying a higher portion of system fixed costs.[3838] He asserted that it is imperative that Consumers consider alternative rate structures that resolve these overpayment issues and encourage heat pump adoption as soon as possible.[3839]

Mr. Reeves described the purpose of rate design as determining a framework for energy pricing that allows for recovery of a utility's cost of service in running the electricity system while attaining policy compliant outcomes.[3840] He maintained that

---

[3834] 6 Tr 3845-3846.
[3835] 6 Tr 3855-3856, Table 1.
[3836] 6 Tr 3856-3857.
[3837] 6 Tr 3851-3852.
[3838] 6 Tr 3852.
[3839] 6 Tr 3846.
[3840] 6 Tr 3862

under Consumers' current rates, as more customers electrify, these customers will generate more revenue for the utility and pay a larger portion of Consumers' fixed costs of service, effectively subsidizing other customers. He contended that this violates the principle that costs should be fairly attributed and paid for by the customers that cause them to occur.[3841]

He asserted that a well-designed seasonal rate, more closely aligned with the marginal cost of energy, and which corrects for potential overpayment of fixed costs, would more closely reflect heat pump customers' costs to the system.[3842] He added that an EH/HP rate could be designed to be revenue neutral, address the overpayment issue, and be structured to reduce energy bills for heat pump customers by setting rates at a level designed to recover revenue directly associated with the additional costs imposed on the grid.[3843] Alternatively, he posited, an EH/HP rate could be designed so that there are shared benefits where all customers are better off as a function of cost reallocation, though still revenue neutral for the utility.[3844] He acknowledged that as more customers adopt an EH/HP rate over time, it may be necessary to revisit and revise the rate to better reflect either changing marginal costs or cost allocation across the residential class and the possibility that the increase in energy and demand will introduce new season-specific costs that will need to be recovered. [3845]

Mr. Reeves testified that at least one Michigan utility, Upper Peninsula Power Company (UPPCO), currently offers an EH/HP rate to residential and commercial

---

[3841] 6 Tr 3866.
[3842] 6 Tr 3869.
[3843] 6 Tr 3870-3871.
[3844] 6 Tr 3871.
[3845] 6 Tr 3871-3872.

customers.[3846] And he stated that from 1963 to 2008, Consumers offered a residential space heating rate to customers with permanently installed electric heating used as the primary heating source.[3847] According to Mr. Reeves, there are also several examples of recently approved EH/HP rates in other states, such as Massachusetts, Maine, Minnesota, and New York.[3848] He also testified that the ACEEE identified an EH/HP rate as the best approach to increase the adoption of heat pumps and guard against increasing energy bills associated with added electric heating loads.[3849]

Mr. Reeves recommended that the Commission require Consumers to work with Staff and interested parties to develop a proposal for an EH/HP rate and present the proposal to the Commission within 12 months of the order resolving this rate case, either as part of a future rate case or a stand-alone proposal.[3850] Mr. Reeves testified that Consumers should consider the following elements when designing the rate: 1) options for both seasonal and temporal differentiation; 2) EH/HP rates for residential and non-residential customers; 3) tradeoffs between rate designs focused on electric heating in general and those focused on technologies such as prompting heat pumps; 4) tradeoffs relating to eligibility requirements and verification (e.g., self-attestation, consumption analysis, submetering); and 5) delivery of the new rate, including strategies and tools for customer and contractor education, such as rate impact calculators and opt-out design strategies.[3851]

[3846] 6 Tr 3853.
[3847] 6 Tr 3853-3854.
[3848] 6 Tr 3872-3875.
[3849] 6 Tr 3875.
[3850] 6 Tr 3848.
[3851] 6 Tr 3848-3849.

In rebuttal, Ms. Connolly stated that Consumers does not oppose "exploring" an EH/HP rate design, but it disagrees with the "prescriptive approach" outlined by Mr. Reeves. Ms. Connolly testified that a 12-month timeline is impractical, but Consumers can investigate an EH/HP rate in its next rate case, which it believes is the best forum to address the idea, and would attempt to bring interested parties together before then to solicit ideas.[3852] Consumers' brief reiterates Ms. Connolly's rebuttal testimony.

Based on Consumers' rebuttal testimony, MNSC modified the timeline of its recommendation and now recommends that the Commission direct Consumers to begin developing an EH/HP rate and hold at least one collaborative session to solicit input within 12 months of its order in this rate case and to present a proposal for an EH/HP rate that reflects the factors presented in MNSC's testimony in its next filed general electric rate case.[3853]

Staff's reply brief concurs that at least one workgroup meeting should occur concerning the establishment of an EH/HP rate for residential customers.[3854]

Both Consumers and MNSC appear to agree with the development of an EH/HP rate in Consumers' next rate case and the occurrence of at least one collaborative session in advance of the rate case to solicit input, which Staff also supports. While Consumers expressed its general disagreement with a prescriptive approach to the rate design, this PFD notes that the elements MNSC's witness listed for consideration were reasonable. Therefore, this PFD recommends that the Commission order that Consumers propose an EH/HP rate in its next rate case, hold a collaborative workgroup

---

[3852] 3 Tr 174.
[3853] MNSC initial brief, p. 130.
[3854] Staff reply brief, p. 12.

meeting to solicit input beforehand, and consider the following when developing the rate: 1) options for both seasonal and temporal differentiation; 2) EH/HP rates for residential and non-residential customers; 3) tradeoffs between rate designs focused on electric heating in general and those focused on technologies such as prompting heat pumps; 4) tradeoffs relating to eligibility requirements and verification (e.g., self-attestation, consumption analysis, submetering); and 5) delivery of the new rate, including strategies and tools for customer and contractor education, such as rate impact calculators and opt-out design strategies.

E. Tariff Issues

1. Service Connection Fee

Company witness Brittani Gray presented the Company's proposed tariff language changes to its electric rate schedules.[3855] Supporting her testimony, Ms. Gray sponsored two exhibits – a Summary of Tariff Changes, and the Proposed Electric Tariff Sheets.[3856]

Ms. Gray testified that the Company proposed introducing an overhead service connection fee and updating the existing underground service connection fee for Residential and General Service Customers. The changes are based on inflation rates and a three-year average length of service.[3857] Ms. Gray stated that the Company proposed to introduce a service fee for overhead connections that mirrors the proposed fee for underground connections. This change was intended to promote fairness by applying a uniform fee structure for new service installations, regardless of the

[3855] 2 Tr 668.
[3856] 2 Tr 668; Exhibits A-16, A-96.
[3857] 2 Tr 669.

connection type. Additionally, the proposal supported customer adoption of the more reliable underground option and aligns with the Company's Reliability Roadmap. Ms. Gray testified that the Company also proposed revising the current underground service connection fee to reflect inflation-related cost increases that have occurred since the fees were last updated in Case No. U-9346 approved for service rendered on and after August 6, 1993.[3858] The proposed fees were based on a three-year average service connection length of 132 feet. To simplify the structure and better reflect current economic conditions, the Company proposed replacing the existing per-foot charge with a flat fee of $1,300 for Residential Customers and $2,200 for General Service Customers. These proposed amounts were derived by applying the cumulative inflation rate over the past 31 years to the current per-foot charges and multiplying by the average service length.[3859]

Ms. Gray next explained the Company's proposed changes to Rule C5.4 Shut Off Protection Plan. She noted the Company proposed to increase the eligibility for the Shut Off Protection Plan ("SPP") from 200% to 400% of the federal poverty level. This change aimed to provide support for a larger segment of moderate-income customers.[3860]

Ms. Gray also explained the changes to Rule C5.5 regarding non-transmitting meters. She noted that eligible customers who elect a non-transmitting meter are served under the applicable rates in accordance with Rule C5.5, Non-Transmitting Meter Provision. Currently, two potential upfront charges apply, depending on when the

[3858] 2 Tr 669.
[3859] 2 Tr 669-70.
[3860] 2 Tr 670.

customer provided notice to opt out. However, because the Company has completed the initial deployment of Advanced Metering Infrastructure ("AMI") meters for all customers who have not opted out, the distinction between early and late opt-outs was no longer necessary. Accordingly, Ms. Gray stated the Company proposed simplifying the fee structure by implementing a single upfront charge for all customers who elect to opt out, regardless of timing. Ms. Gray stated that this change is intended to promote consistency and fairness in the administration of the provision, while maintaining the existing eligibility criteria as defined in the tariff.[3861] She also noted the Company proposed an updated AMI opt-out charges based on a re-evaluation conducted in compliance with the Commission's directive in the Final Order in Case No. U-21585. The proposed changes were addressed in Company witness Michael Kelly's testimony.[3862]

Ms. Gray testified the Company also proposed removing the tariff sheets associated with the Experimental Advanced Renewable Program ("EARP")–Anaerobic Digestion Program ("AD Program") because the program is closed to new participants and has had no active customers since May 2023. The removal reflects the current status of the program and ensures the tariff remains accurate and up to date.[3863]

Ms. Gray next addressed the proposed changes to the General Service Secondary Time of Use Rate (GSTU). She stated the Company proposed revising the availability of Rate GSTU to clarify that customers may participate in Demand Response ("DR") programs while taking service under this rate. Full-Service customers taking

---

[3861] 2 Tr 670-71.
[3862] 2 Tr 671.
[3863] 2 Tr 671.

service under Rate GSTU are currently eligible to participate in DR programs, as outlined on Sheet No. D-10.00, Rate Categories and Provisions. The Company noted that the proposed revision is intended to clarify the eligibility within the GSTU tariff itself, ensuring consistency and transparency in how the rate is administered.[3864]

Per Ms. Gray, the Company proposed revising the Aggregate Peak Demand Service ("GAP") provision that allowed for discretionary enrollment of customers who may not meet all the stated eligibility criteria. Specifically, she stated the Company sought the ability to consider participation by customers with fewer than seven accounts and/or accounts with a lower average On-Peak Billing Demand than the current 250 kW demand threshold. This flexibility would be exercised solely at the Company's discretion and would not alter the fundamental structure or intent of the provision.[3865] This change would provide the Company with administrative flexibility to accommodate unique customer circumstances that may not fit neatly within the existing eligibility framework without requiring a formal tariff revision each time. This change would not alter the structure or pricing of the GAP provision and would not be expected to impact other customers.[3866]

Ms. Gray testified that the Company proposed adding a Power Factor adjustment to Rate LED. This adjustment was like the recently approved Power Factor adjustment for Rates GP, GPD, GPTU, and EIP in Case No. U-21585, but with an increased penalty band – up to an average Power Factor of 0.909 – compared to the penalty bands for these other rates. Additionally, she stated the Company proposed including a

---

[3864] 2 Tr 671.
[3865] 2 Tr 672.
[3866] 2 Tr 672.

facilities allowance.[3867] She noted that other proposed tariff changes are contained in the Summary of Tariff Changes.[3868]

Staff witness Nicholas Evans addressed the Company's proposed tariff changes, noting that Staff only agreed with some of them.[3869] He reiterated that the Company proposed the following tariff changes:

1. For original installations of underground service connections from underground distribution systems, for mobile home parks, the non-refundable contribution in aid of construction (CIAC) shall be a flat fee of $1,300, which is change from the current $4.50 per foot of required trench.

2. For installations of overhead service connections for residential customers, the developer or customer shall make a non-refundable contribution of $1,300. There currently is no fee for these connections.

3. For installations of overhead service connections for general service customers, the developer or customer shall make a refundable contribution of $2,200. There currently is no fee for these connections.

4. For the installation of underground service connections for residential customers, the developer or customer shall make a non-refundable contribution of $1,300. The current contribution is $350 for the first 150 feet and $4.50 for each additional foot.

[3867] 2 Tr 672-73.
[3868] 2 Tr 673; Exhibit A-96.
[3869] 6 Tr 4453-54.

5. For the installation of underground service connections for general service customers, the developer or customer shall make a refundable contribution of $2,200. The current contribution is $6.50 per trench foot.[3870]

Consumers proposed in each case that the flat fee applied to the route selected by the Company, and for an alternate route requested by the customer and mutually agreed upon by the Company and the customer, the contribution shall be the flat fee plus any additional costs in excess of those associated with the route specified by the Company.[3871]

Mr. Evans noted that Staff agreed that the costs need to be updated, overhead service connections should require the customer or developer to pay a fee, and the Company can charge additional costs for alternate routes that are longer and more challenging. However, he stated that Staff does not agree with the flat fee structure. The Company calculated the $1,300 and $2,200 amounts based on a three-year average service connection length of 132 feet multiplied by updated per-foot costs. Mr. Evans also expressed Staff's concern that customers with service connection lengths shorter than 132 feet would be subsidizing customers with much longer service connection lengths. Mr. Evans asserted that Staff recommended the Company maintain the existing fee structure with a per foot charge for each type of connection. For installations of overhead service connections for residential and general service customers, which currently do not have fees, the Company should propose fees or contributions that include per-foot charges in its next rate case.[3872]

[3870] 6 Tr 4453-54.
[3871] 6 Tr 4454.
[3872] 6 Tr 4454.

In its brief, the Company addresses the proposed Service Connection Fee and Staff's recommended adjustments. As to the new overhead service fee, the Company largely reiterates testimony and argues that its proposal will support customer adoption of the more reliable underground option for services.[3873] As to increasing the underground service connection fee and Staff's disagreement with the proposed flat fee, the Company argues in support of the flat fee, which is consistent with current practice, creates billing efficiencies, and prevents rebilling if the actual footage differs from the original quote. The Company argues that charging a flat fee is reasonable because a significant portion of installing a new service involves fixed costs associated with the crew being onsite for the work, and those fixed costs are included in the Company's proposed fee structure.[3874] The Company also argues that it has protections in place in the proposed tariff to mitigate Staff's concern with subsidization. The Company concludes that its proposal is based on average service length, promotes more reliable underground services, updates stale fees, and provides protections against subsidization. Therefore, the Company asserts the Commission should approve its reasonable update to the service connection fees, and the addition of the overhead service connection fee, in this case rather than require a new request in the future.[3875]

In its brief, Staff reiterates its recommendations and the Company's arguments for the tariff changes involving flat fees. Staff then stands by its initial recommendation arguing that flat fees are not justified just because a significant portion of installing a new service involves fixed costs; not all costs are fixed, and the fee structure should

---

[3873] Company brief, pp. 423-24.
[3874] Company brief, p. 425.
[3875] Company brief, p. 425.

reflect the variable costs to some degree.[3876] Staff is willing to accept a fee structure that has a fixed fee component, like the $350 for the first 150 feet that is currently in place. However, Staff argues there should be a per foot charge component that would apply past a certain distance. In Staff's opinion, the Company's proposal puts too much emphasis on efficiency and not enough on fairness. Finally, Staff argues that the degree to which the Company's proposal protects customers from subsidization is not enough, and per-foot charges are necessary for sufficient protection.[3877]

This PFD acknowledges the Company's justification for a flat service connection fee; however, it concurs with Staff that a flat fee only, rather than a flat fee with a per foot charge after a certain distance, is not justified, and emphasizes efficiency over fairness. Therefore, this PFD recommends the Commission direct the Company to create a fee structure that covers the fixed costs but also reflects the variable costs – protecting the rate payers from subsidization and ensuring fairness.

2. AMI Opt-Out

The Commission's March 1, 2024 Order in Case No. U-21389 stated: "[a]s set forth in this order, and in lieu of the continued provision of future advanced metering infrastructure business case updates, Consumers Energy Company and the Commission Staff shall meet as soon as reasonably possible after the date of this order to coordinate on appropriate value-focused advanced metering infrastructure metrics and elements for the company to include in its future rate case filings." Mr. Kelly stated that the Company met with Staff on three occasions to coordinate appropriate value-

[3876] Staff brief, pp. 165-67.
[3877] Staff brief, p. 167.

focused AMI metrics and elements for the Company to include in its future rate case filings.[3878]

In Case No. U-21585, the MPSC Staff recommended the Company re-evaluate AMI Opt-out Charges and rates before the next rate case to ensure that they reflected the cost of service. In its final Order in Case No. U-21585, the Commission agreed and directed the Company to undertake this update for inclusion in the instant case.[3879] Mr. Kelly stated that AMI Opt-out Charges were intended for customers who elected to have a non-transmitting meter. By selecting this option, the customer agreed to cost-based up-front and ongoing monthly charges.[3880] The monthly charge for opting out of an AMI smart meter included the costs associated with manual inspections and readings of the meters as well as ongoing non-transmitting meter costs.[3881] Mr. Kelly noted that the ongoing costs included: Meter Reading; Meter Testing Program for Legacy Meters; Re-read order; Monitoring, Tracking and correcting accounts; Non-transmitting Meter Retention; Meter Reader Handheld Device Purchases; and Net of AMI and Legacy capital costs.[3882] Mr. Kelly testified that the Company proposed to increase AMI Opt-out Charges to: Upfront Charge to replace an existing AMI meter with a Legacy Non-transmitting Meter: $216.22 one-time fee (from $123.91); and, a Monthly Charge: $3.09/month (From $3.00).[3883]

Staff witness Hansen testified that the Company proposed updated AMI Opt-Out charges due to the Commission order in Case No. U-21585 in which the Commission

---

[3878] 3 Tr 1560; Exhibit A-133.
[3879] 3 Tr 1560.
[3880] 3 Tr 1561.
[3881] 3 Tr 1561.
[3882] 3 Tr 1562.
[3883] 3 Tr 1561-62; Exhibit A-136.

ordered the Company to re-evaluate the charges to ensure alignment with cost-of-service and to include the updated charges in its next rate case.[3884] The Company proposed to change the upfront charge for the meter installation from $123.91 to $216.22 and the monthly charge from $3.00 to $3.09.[3885] Staff inquired about the cost breakdown for each component in audit and the Company explained that the incorrect basis was used for the $93 cost and that it should be equal to the $45 cost, since it was reflective of the potential to replace a non-transmitting meter back to a standard AMI meter in the future.[3886] This changed the proposed upfront charge from $216.22 to $168.07.[3887] Staff recommended the Commission adopt this updated opt-out upfront charge of $168.07.[3888]

In audit, Staff requested a breakdown of each of the costs, which the Company provided.[3889] The breakdown showed the cost of all non-AMI reads, the number of manual gas reads, the number of manual electric reads, and the number of automated meter reading (AMR) gas reads. The cost was then divided by the total number of reads to arrive at the average read cost. Most of the reads were AMR gas reads, 13.9 million out of 14.2 million, with only 133,000 manual electric reads. Therefore, Staff asserted that this cost was far more reflective of the cost of AMR gas reads than it was of AMI opt-out reads. Staff asked the Company to provide the cost to read the Company's non-transmitting meters to which the Company replied that it does not track the costs to read non-transmitting meters separately from total meter reading costs. As it was currently

---

[3884] 6 Tr 4316; March 21, 2025 order in Case No. U-21585, p. 98.
[3885] 6 Tr 4316.
[3886] 6 Tr 4317; Exhibit S-12.0.
[3887] 6 Tr 4317; Exhibit S-12.2.
[3888] 6 Tr 4317.
[3889] 6 Tr 4317; Exhibit A-136, Exhibit S-12.0, Exhibit S-12.3.

calculated, Staff found that the proposed monthly charge was not reflective of cost-of-service and should be rejected by the Commission.[3890] Therefore, Staff recommended that the Commission require the Company to begin tracking the costs of reading opt out AMI meters so that the Company could propose an updated, cost-of-service based, monthly charge in a future proceeding.[3891]

Mr. Kelly stated that Staff reviewed information the Company provided in audit and calculated that the Company's proposed upfront charge for advanced metering infrastructure ("AMI") opt out of $216.22 should be reduced to $168.07 based on that audit information. Mr. Kelly agreed that the Company's information supported Staff's calculations.[3892] Regarding the Company's proposed monthly charge for AMI opt-outs, Staff stated that the Company's breakdown of costs to support the proposed $3.09 monthly charge did not accurately reflect the Company's monthly cost of reading non-AMI electric meters. Staff asserted that most of the costs seem to apply to reading Automated Meter Reading ("AMR") gas meters, and therefore they did not support a cost-of-service basis for the Company's proposed charge. Mr. Kelly disagreed with Staff's recommendation, stating that it was not clear whether Staff intended that there should be no monthly charge at all until the Company performed this new analysis, or if the existing monthly charge should remain in effect until that time. If Staff intended the former, Mr. Kelly asserted it was not reasonable. The existing charge was already in effect and should not be eliminated until a replacement was available.[3893]

[3890] 6 Tr 4317-18; Exhibit S-12.0.
[3891] 6 Tr 4318.
[3892] 3 Tr 1578.
[3893] 3 Tr 1579.

Mr. Kelly further asserted 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 which supported a charge of $12.61/meter/month.[3894] Mr. Kelly stated that while the Company could investigate separately tracking the costs of reading non-AMI electric meters, there would be challenges because the Company did not have a dedicated electric meter reader team that only reads non-AMI meters.[3895]

In its brief, the Company addressed AMI opt-out reiterating the testimony of Staff and the Company. The Company specifically stated that if the intent is to eliminate the current charge, the Company does not agree that would be reasonable because the monthly cost of reading non-AMI electric meters is not $0.00.[3896] The Company then noted that it provided an alternative analysis based on an allocation of labor and associated overhead for supervision, support, and vehicle costs for non-transmitting meters which supported a Monthly Meter Charge of $12.61, arguing that it would not be reasonable to eliminate the monthly charge in this case.[3897] The Company also reiterated there would be challenges for the Company to separately track these costs because the Company does not have a dedicated electric meter reader team that only reads non-AMI meters.[3898]

In its brief, Staff recommended that the Commission adopt the Company's proposed AMI opt-out upfront charge, which was updated to $168.07 by the Company

---

[3894] 3 Tr 1579; Exhibit A-220.
[3895] 3 Tr 1579.
[3896] Company brief, pp. 426-27.
[3897] Company brief, p. 427.
[3898] Company brief, p. 427.

through audit. In rebuttal, the Company agreed with this recommendation.[3899] Staff also recommended that the Commission reject the Company's proposed monthly AMI opt-out charge. Based on the calculation of the monthly charge provided to Staff by the Company, Staff testified that the proposed charge is not reflective of cost-of-service. The Commission's order in Case No. U-21585 stated that a re-evaluation of AMI opt-out charges is prudent to ensure alignment with the cost-of-service, therefore, the Commission should require the Company to track the costs of reading non-AMI meters and to propose an updated monthly charge in a future rate case.[3900]

This PFD notes that the Company reviewed the charges for AMI opt-out and proposed a revision that was evaluated and modified by Staff in this case, complying with the Commission's direction to re-evaluate AMI opt-out upfront and monthly charges. This PFD concurs with the Company and Staff and recommends that the Commission adopt the revised AMI opt-out upfront charge of $168.07 as reflective of cost-of-service. Regarding the revised monthly charge, this PFD notes Staff's assertion that the proposed cost was more reflective of the cost of AMR gas reads than of AMI opt-out reads because it was the average of all non-AMI reads, of which only 133,000 (out of 14.2 million) were manual electric reads, may be valid; however, the Company's point that establishing a separate process to track only 133,000 non-AMI meters would likely result in an even higher charge may also be valid. Looking at the Company's estimated charge of $12.61/meter/month, based on an allocation of labor and associated overhead, the proposed charge of $3.09 appears both reasonable and

[3899] Staff brief, p. 168.
[3900] Staff brief, p. 169.

prudent even if not necessarily aligned with cost of service. Therefore, this PFD recommends the Commission adopt the proposed adjusted monthly charge of $3.09. However, if the Commission would like to study this cost further, it could also direct the Company to investigate separately tracking the costs of reading non-AMI meters so it could propose an updated, cost-of-service based, monthly charge in a future proceeding.

VIII.

OTHER ISSUES

A. Distribution Investment Recovery Mechanism

Ms. Myers testified that Consumers is proposing to extend the Distribution IRM, which would end on February 28, 2026, for two additional years commencing on May 1, 2026, consistent with the start of the test year.[3901] She testified that Consumers proposes $352,280,000 of IRM spending for each of the two years in the following investment categories (LVD Reliability Subprograms): $276,191,000 for LVD Lines Reliability (Targeted Circuit Improvements and Pole Replacements); 2) $11,647,000 for Resiliency (Fractionalization); 3) $4,098,000 for System Protection; 4) $30,344,000 for LVD Repetitive Outages; and 5) $30,000,000 for the Vulnerable Communities Resiliency Plan (VCRP).[3902] She noted that the proposal includes two additional investment categories (LVD Repetitive Outages and the VCRP), but otherwise

[3901] 3 Tr 1828.
[3902] 3 Tr 1828-1829.

Consumers proposes using the same IRM process, including planning meetings, reporting metrics, and reconciliation process, as approved in Case No. U-21585.[3903]

According to Ms. Meyers, the IRM provides customer protections, transparency, collaboration, and increased accountability for distribution investments. She explained:

> Customers will benefit from the certainty of investments in the capital programs included in the IRM that are critical to improved reliability. In addition, the reconciliation process will ensure customers do not pay to support investments if they are not actually made. The IRM brings additional transparency and accountability to project planning and results through reconciliation filings, collaboration on IRM project planning, and reporting on the execution of those plans.[3904]

Mr. Kelly explained the reasoning behind adding LVD Repetitive Outages and the VCRP to the IRM. He testified that the LVD Repetitive Outages subprogram, which addresses locations on the system where customers experience frequent outages, is being added to improve Consumers' recent CEMI-4 performance. He asserted that without the additional IRM funding for the subprogram Consumers would not be able to meet the Commission's Service Quality and Reliability Standards.[3905] Mr. Kelly explained that the addition of the VCRP to the IRM aligns with the Commission's "desire that any IRM should see investments deployed equitably, and that an IRM should not 'exacerbate or perpetuate racial or socioeconomic disparities in service.'"[3906] He added that the VCRP will provide assurance that disadvantaged communities receive better than average all-weather reliability.[3907]

[3903] 3 Tr 1828, 1830.
[3904] 3 Tr 1830.
[3905] 3 Tr 1473.
[3906] 3 Tr 1474, quoting Case No. U-21389, Order, March 1, 2024, p. 273.
[3907] 3 Tr 1474.

Mr. Kelly described Consumers' historical IRM performance and explained that the Company did not achieve its targeted spending during the first year of the IRM (March 1, 2024 to February 28, 2025) largely due to multiple permitting delays associated with fractionalization projects in the Resiliency subprogram.[3908] He asserted however, that the delayed projects will be completed in 2025 in the second year of the IRM.[3909] Mr. Kelly testified that the IRM has positively impacted reliability and resiliency, leading to improved SAIDI excluding MEDS performance of 3 minutes and improving All-weather SAIDI by 12 minutes while experiencing one less MED than in 2024.[3910] He also testified that IRM investments were deployed in an equitable manner, noting that Consumers invested 9.5% or $6,315,000, of the $66,132,000 total spending in EJ communities despite EJ communities comprising only 4.1% to 9.2% of Consumers' service territory.[3911]

Mr. Kelly remarked that, "the IRM serves as a way [to] ensure proactive spending on projects that are beneficial to deliver a reliable and resilient system."[3912] He explained that ring-fencing capital, as the IRM does, ensures that it will not be diverted to other purposes and if the funding is not spent, customers are refunded. He noted for instance that customers will receive a refund due to the aforementioned fractionalization delays in the Resiliency subprogram.[3913]

[3908] 3 Tr 1476-1477, Fig. 33 and Fig. 34.
[3909] 3 Tr 1477.
[3910] 3 Tr 1478.
[3911] Id.
[3912] Id.
[3913] Id.

Ms. Myers noted that if the Commission adjusts the capital spending included in the IRM, base rates will need to be adjusted to recover the revenue of any capital spending not included in the IRM.[3914]

Ms. Connolly presented an illustrative calculation of the proposed IRM surcharge, showing how Consumers proposes to collect the IRM revenue requirement from each customer class.[3915] She explained that the surcharge is based on test year sales and would apply to both full service and retail open access customers and be effective for service rendered on and after May 1, 2026 and on and after May 1, 2027.[3916] She noted that during the IRM reconciliation process, if it was determined that the actual IRM revenue requirement fell short of the Commission-approved amount collected through the surcharge, then the Company would refund customers the difference.[3917]

Mr. Evans testified that Staff supports Consumers' proposed two-year extension of the IRM, but with three changes.[3918] First, Staff recommends the removal of $6,068,000 from each year of the IRM due to Staff's recommended 20% reduction to test year capital expenditures for the LVD Repetitive Outages subprogram. Mr. Evans noted that the recommendation was a compromise between recent underspending by Consumers and the Commission's position in Case No. U-21585 that this subprogram is valuable to the Company's CEMI-4 performance.[3919] He asserted that since Staff's concerns about underspending apply to years beyond the test year, Staff also

---

[3914] 3 Tr 1831.
[3915] 3 Tr 163; Ex. A-68.
[3916] 3 Tr 163.
[3917] Id.
[3918] 6 Tr 4449.
[3919] 6 Tr 4450.

recommends that $6,068,000 be removed from the second year of the IRM, May 1, 2027 – April 30, 2028, as well.[3920]

Next, Mr. Evans testified that Staff recommends the removal of the entire VCRP spending of $30 million from the IRM and its transfer to the rate base. He stated that based on Mr. Kelly's testimony that Environmental Justice (EJ) communities in Consumers' territory have comparatively good reliability, Staff believes that while Consumers should invest in these communities, recovery of these expenditures does not need to occur in the IRM.[3921]

According to Mr. Evans, Staff's third recommended change is to lower the rate of return for the second proposed year of the IRM (May 1, 2027 – April 30, 2028) as Staff believes it should be lower than the pretax rate of return (but no lower than the short-term debt rate) approved in this case.[3922] He stated that once the investments are found to be prudent and reasonable for inclusion in base rates in a future rate case, Staff intends for the normal ROR to apply.[3923]

He stated that the reason for the recommendation is Consumers' past underinvestment in the distribution system. He noted Consumers' distribution investments during the 2010s:

2010: $289,222,000
2011: $323,266,000
2013: $363,383,000
2014: $337,340,000
2015: $352,395,000
2016: $419,535,000
2017: $447,874,000

[3920] Id.
[3921] Id.
[3922] 6 Tr 4449.
[3923] Id.

2018: $533,167,000.[3924]

He testified that in contrast, Consumers is projecting to spend $1,152,221,000 in 2025 and $1,529,914,000 in the test year.[3925] He also noted that the Reliability Roadmap shows Consumers plans to increase this spending to $1,959 million in 2029.[3926] He maintained that this distribution spending is 4-6 times larger than the spending that occurred in most of the 2010s, which he asserted points to the earlier spending being insufficient.[3927] He testified that Staff believes the projections for 2026-2029 are probably closer in magnitude to what the system requires than the amounts that were spent a decade before, which also points to the underinvestment.[3928] He asserted that Staff made a similar recommendation regarding the rate of return for DTE's IRM in Case No. U-21860.[3929]

Lastly, Mr. Evans remarked that if the Commission thinks extending the IRM for two years is too long, "it can always approve just one year," and Staff is also of the opinion that the Commission can reduce a year's approved IRM amount in a subsequent rate case prior to that year occurring.[3930]

UCC witness Cira-Reyes testified that while he generally supports investments in vulnerable communities, he has concerns about approving another IRM before reconciliation for the current IRM has been completed and approved.[3931] He asserted that Consumers' current reconciliation filing shows that it exceeded its Year 1 approved

---

[3924] 6 Tr 4451 (citations omitted).
[3925] Id.; Ex. A-113.
[3926] 6 Tr 4451-4452, Fig. 138; Ex. A-129.
[3927] 6 Tr 4452.
[3928] Id.
[3929] 6 Tr 4452-4453.
[3930] 6 Tr 4453.
[3931] 3 Tr 2331.

IRM spending by more than $16.8 million, yet it did not complete all of its proposed projects.[3932] He explained that while Consumers was approved to spend $8.973 to complete four fractionalization projects, it spent nearly $8 million but only completed one project due to what the Company called "a series of delays."[3933] He testified that Consumers should elaborate on why its Year 1 cost projections were so inaccurate and must show through reconciliation of its Year 2 funding that it can complete projects on time and within budget.[3934] He emphasized that he supports the investments in vulnerable communities, but he also thinks that ratepayers should not continuously absorb unexpected cost increases and less than anticipated reliability improvements.[3935]

Mr. Cira-Reyes also testified that he would have appreciated it if Consumers had included a more thorough equity analysis in its current reconciliation application.[3936] He stated that while Consumers noted that it spent 9.5% of the IRM spending on EJ communities, which represent 4.1% to 9.2% of Consumers' service territory, it is not apparent how the expenditures compare to the overall need in EJ communities.[3937] According to Mr. Cira-Reyes, it is entirely possible that the Company should have devoted an even higher percentage of funds to EJ communities if their needs were proportionately greater.[3938] To that end, it would have been helpful if the Company could have tied the analysis of its Year 1 IRM in the reconciliation case and this case to the

---

[3932] Id., citing Case No. U-21918, Kelly Direct Testimony, May 30, 2025, p. 4.
[3933] 3 Tr 2331-2332, citing Case No. U-21918, Kelly Direct Testimony, May 30, 2025, p. 105.
[3934] 3 Tr 2332.
[3935] Id.
[3936] Id.
[3937] 3 Tr 2333, citing Case No. U-21918, Kelly Direct Testimony, May 30, 2025, p. 8.
[3938] 3 Tr 2333.

needs in EJ communities.[3939] He averred that "[d]oing so would have spoken more directly to the Commission's mandate that Consumers present analysis on 'whether the investments are, in fact, being deployed equitably, whether the investments exacerbate or perpetuate racial or socioeconomic disparities in service, whether there has been a positive impact on reliability and resilience, whether there is sufficient opportunity for scrutiny of the investments, and whether customers have benefitted from the IRM mechanism.'"[3940] Ultimately, Mr. Cira-Reyes, contended, Consumers must prove it can deliver on its promise to establish a more reliable and resilient network for all its customers, especially for LMI and BIPOC customers, without overspending ratepayer dollars.[3941]

Finally, Mr. Cira-Reyes testified that while he has argued against multi-year IRMs in the past, he believes that a short-term IRM could be a desirable model for funding reliability improvements because it creates greater accountability for the utility to follow through on promised investments while providing intervenors and consumer watchdogs sufficient opportunity to scrutinize spending outcomes and ensures that ratepayer funds are spent as efficiently as possible and for the benefit of customers.[3942]

ABATE witness Fitzhenry expressed concerns about Consumers' proposed IRM spending on programs within LVD Lines Reliability. He testified that Consumers' projection that it will replace approximately 10% of poles based on their age is flawed and he proposed that pole replacement spending be based on replacing 5% of poles

---

[3939] Id.
[3940] 3 Tr 2333-2334, quoting Case No. U-21389, Order, March 1, 2024, p. 273.
[3941] 3 Tr 2334-2335.
[3942] 3 Tr 2334.

instead.[3943] This would reduce Consumers' capital expense for pole replacements by 50%, and accordingly he recommended reducing pole replacement spending by $63,750,000 in both years of the IRM.[3944]

He also recommended that the Commission deny Consumers' request for capital expenditures for underground cable rejuvenation (in Targeted Circuit Replacements), which would reduce Consumers' proposed authorized IRM capital expenditures by $45,057,250 in both years.[3945] He contended that the underground cable rejuvenation project does not meet the stated purpose of the IRM, which is to address safety and reliability, and it raises concerns that Consumers is not using the IRM as intended.[3946] He explained that the project involves the replacement of cable that is already located underground, such that the safety and reliability benefits have already been realized, and the project is more accurately characterized as preventative maintenance.[3947]

He stated that his total recommended disallowances would reduce Consumers' proposed IRM capital expenditures by $108.8 million each year.[3948] He maintained that this lowers Consumers' projected test year IRM surcharge revenue deficiency by $5.781 million based on the Company's proposed ROE of 10.25% and a common equity ratio of 50.75%.[3949]

In rebuttal, Ms. Myers testified that it would be inappropriate and punitive to apply a lower rate of return to any portion of the IRM as recommended by Mr. Evans. She

---

[3943] 6 Tr 3721-3723.
[3944] 6 Tr 3723.
[3945] 6 Tr 3724-3725.
[3946] 6 Tr 3724.
[3947] Id.
[3948] 3 Tr 3737, Table CTF-3.
[3949] Id.

maintained that the cost of the capital investments included in the IRM are collected from customers over time through depreciation expense and until the cost of the assets are fully collected, Consumers is required to finance the assets.[3950] She continued that not allowing the Company to recover the full cost of financing based on the reasoning that Consumers previously underinvested in its distribution system is inappropriate rate making.[3951]

She also asserted that if a lower rate of return is applied to the IRM investments, Consumers would be forced to reevaluate using the IRM, which could lead to its discontinuation or a reduction in its scope and the loss of customer benefits.[3952] She also maintained that Staff's position that Consumers has underinvested in the distribution system is belied by Staff's past recommendations to disallow Consumers' proposed distribution capital investments.[3953] She pointed out that Staff proposed to disallow over 10% of Consumers' requested spending in Case U-18322 and nearly 15% of the Company's requested spending in Case U-20134.[3954] She asserted further that using current ratemaking to punish Consumers for investments made a decade prior would be unfair, unprecedented, and illogical.[3955] Additionally, she maintained that "reducing the return on the investments needed now would not reflect the actual financing costs of the needed investments."[3956] She contended that the investments

---

[3950] 3 Tr 1843.
[3951] Id.
[3952] 3 Tr 1844.
[3953] Id.
[3954] 3 Tr 1844-1845, Table 1.
[3955] 3 Tr 1845.
[3956] Id.

included in the IRM should receive the same return applied to all similar long-term capital investments.[3957]

Mr. Kelly responded to Mr. Evans' recommendation to remove the VCRP funding from the IRM. He stated that the VCRP is included in the IRM "precisely because it is important to invest in EJ communities" and the IRM ensures that the investments are made.[3958] Furthermore, he added, the Commission's Order in Case No. U-21389 approving the initial IRM, made it clear that Consumers should show how the IRM promotes system equity and the Company believes that including the VCRP in the IRM provides one clear mechanism for doing this.[3959]

In rebuttal, Mr. Evans disagreed with the adjustments to Consumers' proposed IRM recommended by ABATE and the UCC, asserting that they are too large and Staff's more modest reductions are more appropriate.[3960] He noted that while Staff does not support the VCRP being included in the IRM, Staff does not oppose requiring Consumers to report more thoroughly on the linkage between the percentage of the investments in EJ communities relative to the needs of those communities.[3961]

METC witness Fleck testified in support of Consumers' proposed enhancements to the IRM for vulnerable communities and repetitive outages. He asserted that "such investments can help ensure that reliability of transmission service is maintained in the

---

[3957] 3 Tr 1846.
[3958] 3 Tr 1576.
[3959] 3 Tr 1577.
[3960] 6 Tr 4458.
[3961] Id.

face of extreme weather, increasing electrification of daily life, such as growing numbers of EV ownership, and address service concerns of Consumers' customers."[3962]

In briefing, Consumers largely recaps its witnesses' direct testimony and rebuttal to Mr. Evans. Consumers responds to Mr. Cira-Reyes' recommendations by noting that equity considerations and reconciliation of Year 1 of the IRM are being addressed in Case No. U-21918 and that Year 2 will be reconciled beginning in 2026.[3963] Consumers argues that it is seeking to include the VCRP in its IRM proposal in this case to ensure that the IRM has a positive impact on equity.[3964]

As for ABATE witness Fitzhenry's recommended reductions to pole replacements and targeted circuit improvements, Consumers discusses these in the LVD Distribution Capital Expenditures portion of its brief and notes that the amounts included in the IRM should match the amounts approved for the capital expenditures in the test year.[3965] In the Capital Expenditures section, Consumers points out that its projected pole replacement spending is supported by research from EPRI based on a review of about 3 million poles from 7 utilities.[3966] Consumers also asserts that its underground cable rejuvenation project is cost effective and notes that the Liberty Audit endorsed cable rejuvenation as a sound means to address underground cable reliability problems.[3967]

In its brief, Staff reiterates Mr. Evans' testimony and rejoins Consumers rebuttal, stating that applying less than the pretax ROR to the IRM investments is not punitive

---

[3962] 4 Tr 3191.
[3963] Consumers initial brief, p. 431.
[3964] Id.
[3965] Id.
[3966] Id, p. 50-51; Ex. A-227.
[3967] Consumers initial brief, p. 50.

and emphasizing that the lower return would not be permanent and the normal ROR would apply once the investments are found to be prudent and reasonable for inclusion in rates.[3968] Staff also disagrees with the notion that because Staff recommended disallowances to distribution capital spending in previous cases, it somehow cannot criticize Consumers for underinvesting in the distribution system or recommend a temporary lower ROR for IRM investments.[3969] Staff asserts that In those previous cases, Staff was recommending disallowances for spending that it believed was not reasonable or prudent to be placed into customers' rates. Had the Company proposed larger spending amounts, and those amounts were found, in Staff's judgement, to be reasonable and prudent, Staff would have supported their inclusion in rates.[3970]

In its brief, ABATE argues that Consumers' "dramatic increase" in IRM spending is unreasonable and conflicts with the Commission's approach to the program.[3971] ABATE explains that over Consumers' past two rate cases "the Commission has provided reticent, constrained approval for the Company's IRM, tempered to limit the number of years it may cover as well as the costs included."[3972] ABATE avers that this contrasts with Consumers' proposal to continue the IRM for two more years, approximately quadruple its spending in LVD Lines Reliability, and add two new investment categories.[3973] ABATE contends that these proposals would result in

[3968] Staff initial brief, p. 164.
[3969] Id.
[3970] Id.
[3971] ABATE initial brief, p. 88.
[3972] Id., p. 88-89, citing Case No. U-21389, Order, March 1, 2024, p. 272-273 and Case No. U-21585, Order, March 21, 2025, p. 364-366.
[3973] Id., p. 89.

exorbitant rate increases that Consumers has not demonstrated are reasonable or prudent.[3974]

ABATE argues that the IRM concept and process may not be objectionable, but only to the extent that the Commission ensures three things: 1) there is an urgent and undisputed need for each investment and Consumers has demonstrated that the investments are the most cost effective way to address the need; 2) the years authorized for the IRM do not go beyond the projected test year any more than necessary; and 3) the categories are not defined overly wide, such that Consumers can avoid a necessary investment in a cost category by making up for it with investment in the same category that has a lower degree of need.[3975] ABATE argues that without these guardrails the Company's IRM could quickly become a vehicle for unreasonably and greatly expanding distribution investment beyond projected test year periods without demonstrating that the investment is necessary or cost effective.[3976]

ABATE contends that Consumers' proposed IRM spending for LVD Lines Reliability accounts for approximately 78% of the total $266.0 million (308%) increase in proposed annual IRM capital expenditures and raises concerns about the need and cost-effectiveness of the investments.[3977] ABATE posits that the Commission addressed these same concerns in Consumers' last rate case in the context of a proposed increase to Zonal Health Improvements where the Commission wanted to see more analysis of the most cost effective opportunities to drive reliability improvements.[3978]

[3974] Id.
[3975] Id., p. 90.
[3976] Id.
[3977] Id.
[3978] Id., p. 90-91, citing Case No. U-21585, Order, March 21, 2025, p. 63-64.

ABATE argues that the Commission should maintain this same scrutiny and approach to the Company's current IRM proposal and reduce LVD Lines Reliability spending by at least $108.8 million per year.[3979]

In its brief, the UCC argues that it is necessary to ensure accountability and transparency in the IRM, especially with regard to investments in EJ communities.[3980] The UCC recommends that the Commission do the following: 1) proceed cautiously before approving the proposed IRM extension in this case given the outstanding reconciliation issues in U-21918; 2) track the reconciliation process in U-21918 to understand the information in that case and interactions with the issues before the Commission in this case; 3) mandate quarterly reporting on project completion rates, spending versus budget, and equity outcomes in any extended IRM going forward to create "greater accountability for the utility to follow through on promised investments while providing intervenors and consumer watchdogs sufficient opportunity to scrutinize spending outcomes; and 4) return funds to ratepayers in compliance with the Commission's Order in U-21585 if the reconciliation process in U-21918 reveals that funds designated for particular work were not spent as the Commission has directed.[3981]

The UCC argues further that Consumers' analysis of the equity of Its IRM investments needs to be improved to comply with the Commission's Order in Case No. U-21389.[3982] The UCC contends that to fully comply with the order, Consumers must report "more thoroughly on the linkage between the percentage of investments in EJ communities relative to the needs of those communities" and complete an equity

[3979] Id., p. 91.
[3980] UCC initial brief, p. 101.
[3981] Id., p. 104.
[3982] Id., p. 106-107.

analysis that looks at needs and impacts, not just shares of spending.[3983] UCC maintains that the Commission should reaffirm its commitment to accountability by mandating a comprehensive equity evaluation in the reconciliation process that demonstrates the actual benefits of investments in EJ communities and order quarterly reporting on equity outcomes that directly links the Company's investments in EJ communities to the needs of those communities.[3984]

In its reply, Consumers notes that UCC's recommendation for quarterly reporting on project completion rates, spending versus budget, and equity outcomes in the IRM going forward is presented for the first time in its initial brief. Consumers also contends that this reporting requirement should be rejected because the separate IRM reconciliation already addresses these matters.[3985]

Staff's and ABATE's reply briefs did not address the IRM, while the UCC's reply did not provide any new arguments regarding the IRM.

This PFD finds that Staff and other parties generally support the IRM to the extent that it addresses reliability concerns, its approved funding is not diverted, and unspent expenditures are refunded to customers. This PFD notes that it was mindful of ABATE's suggested guardrails on the IRM when making its recommendations, as they appear reasonable and generally consistent with Commission directives.[3986] This PFD notes further that its recommendations to allow or disallow Consumers' proposed IRM funding is consistent with its recommendations regarding Consumers' proposed test

---

[3983] Id., p. 107.
[3984] Id.
[3985] Consumers reply brief, p. 28.
[3986] See ABATE initial brief, p. 90.

year distribution capital expenditures, and are more thoroughly discussed in that section.

This PFD agrees with Staff's proposed 20% reduction in test year capital expenditures for the LVD Repetitive Outages subprogram and accordingly recommends the removal of $6,068,000 from the annual IRM spending. On the other hand, this PFD disagrees with ABATE's recommended capital reductions to pole replacements and targeted circuit improvements within LVD Lines Reliability and consequently rejects ABATE's recommendation to remove $108.8 million from the IRM.

As to Staff's recommendation to remove the VCRP from the IRP, this PFD declines to adopt this recommendation. This PFD agrees with Consumers that the VCRP aligns with the equity-related goals of the IRM and therefore recommends that the $30 million proposed for the VCRP be recovered through the IRM. Consumers' proposed IRM capital expenditures in the Resiliency and System Protection subprograms were not disputed.

Based on the foregoing, this PFD recommends the following IRM spending:

Capital Spending Program	**IRM 12 months ending April 30, 2027**
LVD Lines Reliability	$276,191,000
Resiliency	$11,647,000
System Protection	$4,098,000
Repetitive Outages	$24,275,200
VCRP	$30,000,000
Total	**$346,211,200**

This PFD recommends that the Commission only extend the IRM through the test year (through April 30, 2027). This will allow further information to be obtained through the reconciliation of Year 1, in Case No. U-21918, and the reconciliation for

Year 2, which will begin in 2026. The additional information will assist in determining whether the IRM is meeting the Commission's stated goals, and if so, the IRM can be extended to April 30, 2028, in Consumers' next rate case. As pointed out by Staff, the Commission can approve just one year of the IRM or reduce a year's approved IRM amount in a subsequent rate case prior to that year occurring.[3987]

The above recommendation renders Staff's proposal to use the short-term debt rate for the second year of the IRM moot. If, however, the Commission extends the IRM for two years, this PFD would recommend applying the same return applied to all similar long-term capital investments as proposed by Consumers. This PFD does not find it appropriate to lower the rate of return based on Consumers' proposed investments in the 2010s.

Turning to the UCC's recommendations, this PFD agrees that the Commission should use Case No. U-21918 and subsequent reconciliation cases to inform its decision-making regarding Consumers' current and future IRM proposals, but this PFD stops short of making any recommendation in this regard, noting that Staff and other parties can obtain information from these cases and present it to the Commission for consideration. This PFD also notes that Consumers is required to return funds to ratepayers if funds dedicated for particular work are not spent as directed.

As to the recommendation that Consumers report quarterly on project completion rates, spending versus budget, and equity outcomes, this PFD agrees with Consumers that quarterly reporting was first mentioned in UCC's initial brief. Additionally, this PFD generally agrees with Consumers that project completion and spend versus budget are

[3987] See 6 Tr 4453.

ostensibly addressed in the reconciliation cases. However, this PFD finds that equity outcomes do not appear to be discussed in the IRM reconciliation cases and the need to provide more explanation regarding equity outcomes was introduced in UCC witness Cira-Reyes's direct testimony. Therefore, because it would assist the Commission to ascertain if equity-related goals of the IRM are being met, this PFD recommends that the Commission require Consumers to report more thoroughly on the linkage between its investments in EJ communities and the need in those communities in its next rate case or direct that equity outcomes be specifically addressed in the IRM reconciliation cases.

B. Distribution System Planning and Analysis

Mr. Kelly stated that the Company's vision for electric distribution was presented primarily through its Reliability Roadmap, which served as the underpinning document for the distribution plans laid out in this rate case.[3988] The Commission first directed the Company to file a five-year distribution plan in Case No. U-17990, primarily to give the Commission visibility into how the Company made distribution investment decisions, and to provide a longer-term outlook into investment plans beyond the single year contained in an electric rate case.[3989] Mr. Kelly stated that Grid Archetypes were introduced in the Company's second plan to consider LVD circuit characteristics beyond reliability metrics to prioritize investments, ensuring that investments were optimally made across the Company's distribution system and across different capital spending programs to ensure that no section of the grid was inadvertently left behind.[3990] The

[3988] 3 Tr 1385-86.
[3989] 3 Tr 1386.
[3990] 3 Tr 1386.

Company allocated capital investment amounts across the archetypes, with each archetype receiving an amount that falls within a range bound by guardrails.[3991] Grid Archetypes are updated periodically, typically every three to four years. The update process involved reviewing and reallocating circuits among the archetypes based on various circuit characteristics and performance metrics, as those characteristics and metrics evolve.[3992]

Mr. Kelly stated that the Company made minor amendments to the 2023 Reliability Roadmap for this case, updating information to reflect another year of actual historical reliability data, and to extend projected investments by another year into the future and address issues highlighted by intervenors.[3993] The 2023 Reliability Roadmap took to heart the Commission's findings on reliability, particularly regarding the ability to improve reliability in the face of increasingly severe weather. As a result, Mr. Kelly averred, the Reliability Roadmap evaluated multiple plausible future scenarios, including a future with increasing severity and frequency of storms, rather than assuming historical weather patterns would continue in the future, and then laid out a multi-year investment plan to address asset deterioration and maintain asset health against identified risks while also hardening assets against increasingly severe weather, so that customer reliability improved even if conditions worsened.[3994] Mr. Kelly pointed out that in any of the scenarios modeled, climate change would result in more severe weather and extreme heat, creating increasing reliability and resiliency challenges for the distribution system. Regardless of climate policy, the Company's modeling projected an

[3991] 3 Tr 1387.
[3992] 3 Tr 1388.
[3993] 3 Tr 1389.
[3994] 3 Tr 1390.

increase of 10-15% in severe weather-related outages by the early 2030s, compared to 2020 levels. Mr. Kelly noted the Company emphasized that the most critical issue to focus on was reliability and resiliency in the face of storms, which was a more immediate threat.[3995]

Mr. Kelly stated that having performed this analysis in developing the 2023 Reliability Roadmap, the Company was better able to identify where increased investment was needed, what kinds of investments were needed, and what levels of investment were needed to harden the system and improve reliability for customers even as weather worsens.[3996] The Company also evaluated other investment glidepaths that could affect what levels of investment were planned on a year-by-year basis, which it also evaluated against the Commission's financial incentives and disincentives mechanism targets, established through the Commission's February 27, 2025 Order in Case No. U-21400.[3997] To address these challenges, Mr. Kelly testified that the Reliability Roadmap outlined the need to increase investment to develop a modern grid capable of mitigating the immediate threats from extreme weather.[3998]

Mr. Kelly then turned to the Commission directed third-party audit and review of all equipment and operations of the Company's distribution system.[3999] The third party, Liberty Consulting Group, spent about a year evaluating the Company before filing its report with the Commission.[4000] He noted that the Company was agreeable to some of Liberty's recommendations regarding distribution investment strategy. Liberty

---

[3995] 3 Tr 1391.
[3996] 3 Tr 1392.
[3997] 3 Tr 1392.
[3998] 3 Tr 1392.
[3999] 3 Tr 1392-93.
[4000] 3 Tr 1392.

recommended the Company place less emphasis on asset age when deciding whether to replace assets, to which the Company was generally agreeable. However, the Company does, in some cases, use age as one of many risk factors in determining whether to replace an asset.[4001]

Liberty also recommended the Company slow the pace of investment as defined in the 2023 Reliability Roadmap and evaluate different timeframes for how the Company could meet its reliability goals.[4002] In response, the Company agreed to supplement the five-year glidepath with seven-year and 10-year glidepaths for comparison.[4003] Liberty also recommended the Company accelerate its forestry line clearing cycle so that the LVD system was on a four- or five-year cycle by 2028, which the Company has taken into account, planning to significantly ramp up its line clearing activity to a five-year cycle, although not as rapidly as recommended by Liberty. The increased forestry spending would lead to some adjustments in year-by-year capital investments but would not eliminate the need for capital investments.[4004] Kelly testified that the Company was also slowing its investment pace in open-wire secondary (OWS) conversions by approximately one half in response to Liberty's recommendation.[4005]

Mr. Kelly next addressed Liberty's comments regarding the Company's historical System Average Interruption Duration Index ("SAIDI") performance, which concluded the Company had not improved its reliability over the past decade. He stated that the Company tracked and reported all-weather SAIDI, a well-established industry standard

---

[4001] 3 Tr 1394.
[4002] 3 Tr 1394.
[4003] 3 Tr 1394.
[4004] 3 Tr 1395.
[4005] 3 Tr 1395.

metric. He also asserted that five-year rolling averages should be used for such comparisons to limit annual variability and to reduce the arbitrariness of which cut-off dates to use.[4006]

Mr. Kelly countered both Liberty's criticism that SAIDI trends were worse in 2022 than in 2014, and MNSC and Attorney General criticism that the Company's reliability performance had not improved relative to its peers,[4007] asserting that the Reliability Roadmap's investments were projected to deliver SAIDI excluding MEDs in the second quartile or better by 2029, or five years after investments began substantially ramping up. The Company maintained this goal of providing its customers with better than average reliability performance, and Mr. Kelly stated the Company had demonstrated clear improvement in delivering reliable service to its customers, having already closed approximately 40% of this gap in performance since the Reliability Roadmap's filing.[4008]

Kelly testified that the Company projected improvement in reliability performance using a model that projects SAIDI, System Average Interruption Frequency Index ("SAIFI"), and Customer Average Interruption Duration Index ("CAIDI") based on historical relationships between these reliability metrics and forestry line clearing spending, capital investment in the distribution system, and certain CAIDI improvements.[4009] The model considered future projected forestry line clearing spending, capital investment in key areas, and CAIDI improvements and, in return, the model projected SAIDI, SAIFI, and CAIDI.[4010]

[4006] 3 Tr 1396-97.
[4007] 3 Tr 1397-98.
[4008] 3 Tr 1399.
[4009] 3 Tr 1400.
[4010] 3 Tr 1400.

While variances were expected in projections, Mr. Kelly stated that the Company had confidence in its modeling of the glidepath given a total net variance over the past five years of seven minutes.[4011] Kelly noted the Company's requested distribution capital investments and distribution O&M spending, as well as the robust line clearing plan, supported the planned glidepath to this improved SAIDI performance for customers.[4012] Mr. Kelly further testified that in some areas, the Company's investments and activities would drive a net reduction in SAIFI over the glidepath period, while other investments were necessary to prevent SAIFI from getting even worse.[4013] He also stated that as the number of outages was reduced, crews would have fewer outages to respond to; this reduction in workload would allow crews to more quickly address outages that do occur which would produce CAIDI savings.[4014]

Kelly asserted that some investments identified in the Reliability Roadmap were intended to address asset health risk, assets that were in poor health and at heightened risk of failure in the near future, an issue that was most prominent when considering the HVD system, substations, and Metro infrastructure.[4015] Mr. Kelly stated that while line clearing was an important part of how the Company was working to improve reliability, line clearing alone was not sufficient. He noted that systemwide line clearing benefits would take time to materialize even as the Company began shifting to a five-year clearing cycle, whereas capital investment in the distribution system had already begun delivering reliability benefits. The downward trend indicated that investments had been

[4011] 3 Tr 1401.
[4012] 3 Tr 1402.
[4013] 3 Tr 1403.
[4014] 3 Tr 1405.
[4015] 3 Tr 1406.

well-targeted, and that they quickly delivered benefits, and should therefore work in conjunction with increases in forestry work.[4016] The Company's investments in hardening the system would reduce the number of customer interruptions and/or make the interruptions shorter, countering the impacts trees had on the system.[4017] While increased line clearing would eventually reach diminishing returns, or a point at which continued increases would not create benefits in a cost-effective way; with the revised line clearing plan, Mr. Kelly asserted the Company only needed to invest in the equivalent of 85 zonal health projects per year. This change in the equivalent number of zonal health projects resulted in an $80 million reduction in the capital that otherwise would have been requested by the Company.[4018] Mr. Kelly averred that the Company would have been able to achieve the Reliability Roadmap goal of second quartile SAIDI a year earlier than originally outlined in 2028 had it not adjusted the capital plan in response to Liberty's recommendations.[4019]

Mr. Kelly then testified regarding the alternatives considered by the Company in developing the Reliability Roadmap and its investment plan.[4020] Mr. Kelly indicated that the Company first considered alternatives to the Reliability Roadmap as a whole and second considered alternatives to individual projects.[4021] Mr. Kelly stated that based on Liberty's recommendation, the Company had also modeled what it would look like for the Company to slow its pace of investment and reach that SAIDI target over seven or 10 years. These slower glidepaths would nearly eliminate the most beneficial reliability

---

[4016] 3 Tr 1407.
[4017] 3 Tr 1409.
[4018] 3 Tr 1409-10.
[4019] 3 Tr 1410.
[4020] 3 Tr 1411.
[4021] 3 Tr 1411.

and resiliency programs for the LVD system.[4022] These plans would reduce capital by approximately an additional $35 million a year for the seven-year glidepath and approximately $50 million a year for the 10-year glidepath and would also result in the Company having a less diverse portfolio of reliability investments.[4023] Mr. Kelly asserted that the slower glidepaths suggested by Liberty would leave the Company's performance lagging in the third quartile until well into the next decade, whereas customers would benefit from the Company's plan for more rapid improvement in reliability.[4024]

Mr. Kelly asserted that the Company was fundamentally committed to delivering reliable electric service to its customers as a core business principle.[4025] Both the Citizens Utility Board of Michigan ("CUB") and the Michigan Department of Attorney General have assessed Michigan utilities as unreliable.[4026] Therefore, the Company must consider the reliability performance that it must deliver to meet the targets established through the Commission's financial incentives and disincentives mechanism, commonly referred to as performance-based ratemaking ("PBR").[4027] Both the Commission and various stakeholders expect significantly improved reliability, which the Company stated could be achieved at the investment levels outlined in the Reliability Roadmap, but not at the reduced investment levels recommended by Liberty.[4028] Mr. Kelly testified that the Company used the Interruption Cost Estimate

---

[4022] 3 Tr 1412.
[4023] 3 Tr 1412-13.
[4024] 3 Tr 1413.
[4025] 3 Tr 1413.
[4026] 3 Tr 1414.
[4027] 3 Tr 1415.
[4028] 3 Tr 1417.

("ICE") Calculator tool developed by Lawrence Berkeley National Laboratory and Resource Innovations, and funded by the Energy Resilience Division of the U.S. Department of Energy's ("DOE") Office of Electricity, which calculated that the Reliability Roadmap SAIDI projection would yield up to $6.1 Billion worth of benefits in avoided outage costs.[4029] For that reason, he stated the Company believed the investments and spending projected in the Reliability Roadmap represented the right mix of work to deliver improved reliability.[4030]

Mr. Kelly testified that to address reliability metrics other than SAIDI excluding MEDs, the Company proposed a new Vulnerable Communities Resiliency Plan (VCRP) with a specific goal of getting communities in economically vulnerable areas into the second quartile of all-weather SAIDI.[4031] Mr. Kelly noted that the Commission established all-weather SAIDI as a metric for its new PBR framework in Case No. U-21400; as the PBR framework was fully implemented, the Company expected to develop even more investments intended to improve all-weather SAIDI and meet the Commission's expectations.[4032] Kelly also averred that the Company had not met the Commission's Service Quality and Reliability Standards for CEMI-4 in recent years. CEMI-4 was designated as a metric in the PBR framework, and the Company increased its investment in its LVD Repetitive Outages sub-program to specifically target this metric.[4033]

[4029] 3 Tr 1417.
[4030] 3 Tr 1418.
[4031] 3 Tr 1421.
[4032] 3 Tr 1421.
[4033] 3 Tr 1422.

Mr. Fitzhenry noted that the Company measured electric service reliability using several reliability metrics, most prominently the System Average Interruption Duration Index (“SAIDI”). Based on the Company’s data from 2015-2024, the SAIDI performance, excluding Major Event Days (“MEDs”), was 155 minutes in 2024, which was better than the projected 170 minutes. However, in its audit report, Liberty Consulting Group assessed the Company's historical SAIDI performance and concluded that reliability had not improved over the past decade, despite increases in total capital and O&M expenditures.[4034]

Mr. Fitzhenry compared the Company’s SAIDI with MEDs (All Days) and SAIDI without MEDs (No MEDs) to other investor-owned utilities in Michigan and states sharing a land border with Michigan (Ohio, Indiana, and Wisconsin) for the period 2020-2024. He noted the purpose of reducing the scope of the reliability comparison analysis to only include neighboring states was so the utilities included in the analysis shared a similar geographic region and were thus impacted by similar weather patterns.[4035] He concluded that Consumers ranked between 12 and 17, depending on the metric and year, with an average rank of about 15 out of 17. This put Consumers at or near the bottom in terms of reliability performance within its peer utilities over the last five years.[4036]

Mr. Fitzhenry also summarized the amount of customer minutes of power interruption (“CMI”) by the outage cause for the last three years (2022-2024). He asserted most outages were the result of trees or trees outside the ROW (52%) and the

---

[4034] 6 Tr 3713-14.
[4035] 6 Tr 3714.
[4036] 6 Tr 3714-15.

second leading cause of outages was the result of weather (26%). Meaning that only 22% of outages were the result of other causes such as equipment failures, car/pole accidents, unique incidents, etc.[4037] Therefore, Mr. Fitzhenry asserted that if the Company intended to make any meaningful improvement to its future reliability metrics, then the primary focus should be on vegetation management as opposed to asset replacement since equipment failures only accounted for a small percentage of total outage minutes.[4038]

Mr. Fitzhenry noted that the Company's distribution plant additions, or capital expenditures, had increased from approximately $590 million in 2020 to $878 million in 2024, an increase of $287 million or 49% in five years. Meanwhile, he noted there had been no discernable trend in the Company's SAIDI with MEDs metric over the same period. This meant that the Company had not been able to reduce customer outage minutes, despite significant increases in the annual distribution capital expenditure levels.[4039]

Mr. Fitzhenry concluded that the Company's position that its reliability was improving was based on a cherry-picked view of its data, selectively focusing on SAIDI excluding MEDs, while ignoring the more critical all-weather SAIDI metric that reflected the actual experiences of its customers. While the Company claimed its SAIDI performance without MEDs was improving, a broader comparison showed that it consistently ranked at the bottom of its peers. The Company's distribution plant additions increased by 49%—or $287 million—over the past five years. This increase in

---

[4037] 6 Tr 3716.
[4038] 6 Tr 3716.
[4039] 6 Tr 3717.

spending has not translated into any meaningful reliability gains for customers. Mr. Fitzhenry asserted the Company should be directing its investment to focus on the primary cause of outages, as opposed to focusing on capital investments to grow future returns.[4040] As a result of his conclusion, Mr. Fitzhenry recommended that the Commission demand that the Company first demonstrate a clear link between its investments and quantifiable improvements in reliability before any further rate increases were considered and that the Commission reduce the Company's proposed distribution capital investments.[4041]

In rebuttal, Mr. Kelly noted that Mr. Fitzhenry suggested that the Company's 2024 SAIDI excluding MEDs of 155 minutes, compared to a projected 170 minutes, was the basis of the Company's claim that reliability investments were producing improvements. Mr. Kelly asserted that SAIDI had been improving in absolute terms since 2021, that the rolling five-year average had been falling since 2022, and that each individual year beginning in 2022 had been substantially better than the five-year rolling average. He further asserted that the Company's analysis using the five-year rolling average was more appropriate than Liberty's approach.[4042]

In rebuttal, Mr. Kelly also noted that weather was only one part of what makes utilities similar or dissimilar for purposes of comparison. Utilities could have dramatically different systems in terms of square mileage, line mileage, customer density, percentage of system overhead versus underground, prevalence of heavily forested

[4040] 6 Tr 3718.
[4041] 6 Tr 3718-19.
[4042] 3 Tr 1594-95.

terrain, and various other factors that could have major implications for reliability.[4043] Mr. Kelly acknowledged that the Company's SAIDI was in the third quartile, and noted that the entire premise of the Reliability Roadmap was to improve the Company's reliability into the second quartile. Mr. Kelly reasserted that the Company's reliability has improved in recent years compared to its peers.[4044]

Mr. Kelly stated that the Company disagreed with Mr. Fitzhenry's assertion that the Company should primarily focus on forestry work as opposed to asset replacement to improve reliability, stating that it was not clear that Mr. Fitzhenry evaluated the Company's rationale for why forestry and capital investments are both important for improving reliability. Mr. Kelly also noted that Mr. Fitzhenry's analysis assumed that any weather-caused outage must have been tree-related; however, weather impacts on the system could cause direct damage to assets even if trees were not involved.[4045] Mr. Kelly noted that Mr. Fitzhenry compared the Company's additions to distribution plant over 2020 through 2024 to the Company's all-weather SAIDI over the same period and accused the Company of cherry-picking reliability by only focusing on SAIDI excluding MEDs when considering if reliability was improving.[4046] In response, Mr. Kelly stated SAIDI excluding MEDs was an IEEE-defined industry standard metric, in widespread use by utilities because it normalized performance data for unusually severe weather.[4047] Mr. Kelly also pointed out that the Company has been introducing new efforts aimed at reducing SAIDI including MEDs for customers, such as the Resiliency

[4043] 3 Tr 1596.
[4044] 3 Tr 1596.
[4045] 3 Tr 1597.
[4046] 3 Tr 1598.
[4047] 3 Tr 1598.

sub-program and the VCRP.[4048] Mr. Kelly asserted that Mr. Fitzhenry's analysis of reliability had multiple flaws and had not addressed much of the evidence on the record.[4049]

In its brief, the Company argues that its distribution strategy to date has been to focus on improving SAIDI excluding MEDs because it better reflects conditions within the Company's control but asserts it does not ignore SAIDI including MEDs.[4050]

In its brief, ABATE relies on the parties' testimony, arguing that the average Consumers customer experiences an unacceptable 339 minutes of outages per year more than the average customer of other electric utilities both within Michigan and in neighboring states despite a massive influx of capital.[4051] ABATE asserts that for Consumers to meet its burden to demonstrate that its investment and cost recovery proposals are reasonable and prudent, the Commission should require that the Company demonstrate a clear link between its investments and quantifiable reliability improvements.[4052]

Mr. Kelly asserted that the Reliability Roadmap stated the four distribution objectives: Safe, Reliable and Resilient, Clean and Equitable, and Competitive; which, taken altogether, provided the Company with a comprehensive distribution strategy.[4053] Mr. Kelly further noted that the electric distribution strategy was also affected by the Company's Clean Energy Plan discussed in greater detail by Ms. Partlan.[4054]

[4048] 3 Tr 1599.
[4049] 3 Tr 1599.
[4050] Company brief, p. 436.
[4051] ABATE brief, p. 14.
[4052] ABATE brief, p. 15.
[4053] 3 Tr 1423.
[4054] 3 Tr 1422.

Mr. Kelly then proceeded to further discuss the four distribution objectives. Starting with safety, he specifically stated that improving overall safety and security for customers and employees remained the top priority. Mr. Kelly testified that capital spending in the Rehabilitation sub-programs proactively replaced assets judged to be at risk of imminent failure by Company personnel. The Reliability Roadmap identified voltage conversions, subsurface transformer replacements, open-wire secondary conversions, and key investments to improve public safety.[4055]

Mr. Kelly testified that the Company continued to invest hundreds of millions of dollars in the distribution system to ensure its reliability and resiliency, repairing and replacing distribution assets, performing line clearing work, and investing in technology and automation projects to modernize the grid.[4056] Specifically, the Company directed $697,127,000 of test year capital toward the Reliability Program and proposed an updated Investment Recovery Mechanism ("IRM") to cover certain capital investments.[4057]

Mr. Kelly stated that the Company also consulted the Electric Power Research Institute's ("EPRI") Distribution Grid Resiliency reports published in 2015, and stayed active in various EPRI working groups, each of which allowed Company personnel to stay up to date with best practices and potential breakthroughs at other utilities or from others doing research.[4058] There were two proposals in this case that specifically supported resiliency against severe weather: fractionalization and undergrounding.[4059]

[4055] 3 Tr 1424.
[4056] 3 Tr 1430.
[4057] 3 Tr 1430.
[4058] 3 Tr 1431.
[4059] 3 Tr 1431.

C. Clean & Equitable Grid

Mr. Kelly then addressed the second objective: a clean and equitable grid. The Company's distribution strategy was aligned with overall clean energy goals that involved increasing sustainability and reducing waste. Mr. Kelly stated the Company also continued to execute on a detailed strategy to understand the distribution reliability experience of Environmental Justice ("EJ") communities, and to address any inequity found to exist.[4060] The Company's distribution investments were also designed to help facilitate the transition to cleaner energy resources by integrating and optimizing Distributed Energy Resources ("DERs") such as rooftop solar, as well as Electric Vehicles ("EVs"), onto the system. The Company's Conservation Voltage Reduction ("CVR") investments reduced system losses, helping the Company meet load demand with less need for generation.[4061] The Company also included EJ factors in its distribution planning and made an effort to ensure its investments were right-sized and appropriately targeted to avoid wasteful overbuilding of the system.[4062] Mr. Kelly also stated that the Company was taking incremental steps to gain expertise around DER deployment, laying the groundwork for this through its DER Optimization initiative which would allow the Company to manage and coordinate Company and third-party owned DER assets, applying best practices and lessons learned to deliver solutions best suited for Michigan and customers.[4063]

Mr. Kelly noted the Company was also pursuing a grant through the Infrastructure Investment and Jobs Act ("IIJA") to begin deploying distributed artificial

[4060] 3 Tr 1440.
[4061] 3 Tr 1440.
[4062] 3 Tr 1440-41.
[4063] 3 Tr 1441.

intelligence (“AI”) modules on residential electric meters to quickly analyze high volumes of data to detect and classify anomalies and improve management of distributed assets.[4064]

Mr. Kelly then testified that the Company was working to optimize load for up to 1 million EVs in its service territory by 2030 in support of the State of Michigan’s policy goals.[4065] Kelly stated that the Company’s current modeling indicated the highest levels of customer technology adoption, like EVs, would likely materialize on specific circuits, and while a limited number of circuits may start to approach their capacity thresholds by 2030, the Company’s system was not likely to experience broader issues until closer to 2050.[4066]

Mr. Kelly testified that as more customers adopt new technologies like DERs and EVs, hosting capacity would become a more prominent issue on the system, and hosting capacity analyses (“HCA”) would be important in addressing any concerns that arise.[4067] In 2020, the MPSC directed the Company to pursue a “phased” approach to developing HCAs and the Company has updated its Phase I analysis and maintains a publicly available updated version on its website.[4068] Kelly indicated that the Company expected to have a more detailed Phase II analysis available by the second half of 2025. For its Phase II analysis, the Company would be able to use maximum load data from 2024 to create a snapshot of detailed hosting capacity information, but because

[4064] 3 Tr 1441.
[4065] 3 Tr 1442.
[4066] 3 Tr 1442.
[4067] 3 Tr 1442.
[4068] 3 Tr 1443.

manual analysis was still required with current capabilities, Phase II maps would be detailed but would not be updated in real time.[4069]

Mr. Kelly stated that the Company agreed with the other parties that in future versions of the EDIIP and/or future rate cases, the Company would study reliability performance and hosting capacity on circuits that overlap with EJ communities, which were defined as "census tracts that are above the 80th percentile on the MiEJScreen Overall Score."[4070] Mr. Kelly presented analyses that indicated: (a) on a systemwide basis, the Company's EJ communities have comparatively good reliability, but (b) there are particular EJ communities that do face reliability challenges, and given their socioeconomic vulnerabilities the Company intended to direct specific new investments to those communities to improve their reliability.[4071] Mr. Kelly testified that the Company's Vulnerable Communities Resiliency Plan ("VCRP") was its plan to accomplish this goal.[4072] The VCRP would ensure that no EJ circuits experienced worse than industry average reliability, and it would do so including MEDs to account for the actual experience of those customers. The VCRP would target EJ circuits, not EJ census tracts, because electrical geography (represented by circuits) did not always align with political geography (represented by census tracts).[4073]

Mr. Kelly stated that the VCRP included incremental investments that aligned with investment types that already take place in the Company's Reliability capital

---

[4069] 3 Tr 1443.
[4070] 3 Tr 1443-44.
[4071] 3 Tr 1444.
[4072] 3 Tr 1444.
[4073] 3 Tr 1444-45.

program, particularly in LVD Lines Reliability and Resiliency.[4074] Kelly testified that the Company was not proposing to take reliability investments already in the 2023 Reliability Roadmap and re-direct those to focus on the VCRP, but to maintain its planned reliability investments, and then perform additional targeted EJ investments.[4075] Test year projects included 32.1 miles of hardening and represented a total of $30,000,000, the first tranche of investments in the plan noted above.[4076] The VCRP identified all EJ circuits, particularly those with poor recent reliability performance, and simply steered direct reliability investment into those circuits.[4077]

Mr. Cira-Reyes testified on behalf of UCC and expressed his concern that the Company was not on track to meet either the timeline or investment levels the Commission approved for its EJ Resiliency Plan. He noted that Consumers provided a list of proposed initial investments under its Vulnerable Communities Resiliency Plan in testimony for the current case; however, these projects only added up to a total of $30 million in investments over the coming year. Consumers witness Kelly reiterated in his testimony that the Company planned to invest $600 million total "[o]ver a period of several years." However, $30 million in the first year would not put the Company on track for the expected $600 million in investments over a 10-year period, a timeline that Mr. Cira-Reyes asserted was already quite conservative for addressing these inequities. He declared that improving reliability for vulnerable communities was an urgent need and should be prioritized as such. He further noted that neither Mr. Kelly nor any other Consumers witness explained why only $30 million in projects were selected for the

[4074] 3 Tr 1445.
[4075] 3 Tr 1446.
[4076] 3 Tr 1446; Exhibit A-167.
[4077] 3 Tr 1447.

current year, or how the Company planned to meet the ten-year targets the Commission agreed with in Case No. U-21585.[4078] Mr. Cira-Reyes further testified that he was concerned that the Company was not making mitigation of disparity in race and socioeconomic status enough of a priority.[4079]

Mr. Cira-Reyes recommended that the Commission take the following actions in response to his concerns: First, require that Consumers provide a detailed plan for meeting the ten-year EJ Resiliency Plan targets that the Commission approved in Case No. U-21585. Consumers' proposal for just $30 million in initial Resiliency Plan investments deserved extra scrutiny when coupled with questions about the Company's interpretation of its EJ reliability regression analysis. Second, require the Company to cease all shutoffs until it could determine why BIPOC customers were experiencing increased shutoff rates and present a plan to stop that bias from continuing. He further asserted that every day that the Company continued to shut off customers without having addressed the cause of this disparity, the Company was potentially committing new discriminatory acts against customers. Furthermore, Mr. Cira-Reyes asserted that the Company should be required to create a fund to compensate customers shutoff by Consumers for improper reasons.[4080]

Mr. Cira-Reyes stated that UCC would like Consumers to provide more information on prioritizing DER investment in EJ communities. He expressed concern that EJ circuits, which would benefit most from DERs due to the greater impact of outages on EJ communities, may have low hosting capacity and, as a result, may be left

---

[4078] 3 Tr 2326.
[4079] 3 Tr 2327.
[4080] 3 Tr 2329.

behind in initial rounds of DER investment and further noted that communities that do not have hosting capacity were put in that position by prior failures to invest by the Company, and it was the Company's responsibility to ensure that upgrades are made quickly to ensure that those communities can realize the benefits of DERs.[4081] Mr. Cira-Reyes recommended the Commission require Consumers to prioritize EJ communities in their HCA analysis and update EJ community grids quickly thereafter to ensure that EJ communities were also able to realize the benefits of early DER investment. He further recommended that the Commission consider requiring both the DER Optimization Initiative and the Vulnerable Communities Resiliency Plan to adopt this goal. Mr. Cira-Reyes also recommended the Company be required to invest in increased hosting capacity in EJ communities as part of the Plan so that EJ communities could benefit from DERs as soon as possible.[4082]

In rebuttal, Mr. Kelly stated that Mr. Cira-Reyes' concerns about whether the Company could meet its investment targets for the VCRP largely mirror the concerns that Mr. Shaver expressed and referred to his rebuttal to Mr. Shaver on the topic.[4083] Mr. Kelly asserted that the full regression analysis addressed Mr. Cira-Reyes' concerns systemic inequities based on race and socioeconomic status. Mr. Kelly stated that there was nothing systemic or unique about EJ census tracts in this context, no across-the-system evidence that they experience worse reliability, but acknowledged that the later more nuanced components of the regression analysis do indicate that there were some

[4081] 3 Tr 2341-42.
[4082] 3 Tr 2345-46.
[4083] 3 Tr 1617.

areas in which some EJ census tracts or circuits had worse reliability outcomes which was why the Company had developed the VCRP.[4084]

In response to the Commission's direction in Case No. U-21585 to include residential shutoffs in its regression analysis, Mr. Kelly stated that the Company determined it would need to retain a third-party consultant to assist with the analysis, and developed a request for proposal that was issued for competitive bidding.[4085] The analysis considered widespread types of Company data as well as publicly available data, particularly on socioeconomic and demographic issues.[4086] A large number of different types of statistical analyses were performed, including different types of regression analyses, to evaluate questions of differing reliability performance and differing experiences with involuntary shutoffs across areas of differing socioeconomic status and other conditions.[4087] He noted that it was possible to group the analyses into a few categories and discussed some of the statistically significant results in that manner. First, multiple analyses compared average reliability of different types of census tracts, comparing EJ vs. non-EJ tracts; urban and rural tracts; low-income and high-income tracts; and high-percent-minority vs. low-percent-minority tracts. Second, multiple regression analyses studied census tract-level reliability. Where statistically significant correlations existed, these analyses showed that higher MiEJScreen scores were correlated with improving reliability. Third, multiple regression analyses studied circuit-level reliability, with particular attention to classifying circuits by whether they served EJ census tracts; whether they served urban census tracts; whether they served

[4084] 3 Tr 1618-19.
[4085] 3 Tr 1447.
[4086] 3 Tr 1447.
[4087] 3 Tr 1448.

low-income census tracts; and whether they served high-percent-minority census tracts.[4088]

Mr. Kelly indicated that a large number of individual analyses performed in this exercise returned no statistically significant results.[4089] In evaluating whether one set of census tracts or the other have better reliability, Mr. Kelly stated that there was 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 averaged better reliability than other census tracts.[4090] However, he noted that the regression analyses of census tract-level and circuit-level reliability further underpinned the need to make targeted investment in those EJ communities that do have poor reliability, given their particular vulnerability to frequent and/or extended outages.[4091]

Boratha Tan testified on behalf of the Clean Energy Organizations (CEO) to address the Company's reliability performance presented in its "Reliability Roadmap." Additionally, he addressed the Company's regression analyses on reliability and residential disconnections.[4092] Mr. Tan addressed the Company's reliability analyses noting that when looking at the five-year rolling comparison for SAIDI (both with and without MEDs), the Company ranks in the fourth quartile relative to its peers. In other words, the Company's SAIDI metrics fell within the bottom 25 percentile relative to the SAIDI metrics of its peers.[4093] The Company also provided an environmental justice-

[4088] 3 Tr 1448-49; Exhibit A-138.
[4089] 3 Tr 1450.
[4090] 3 Tr 1450.
[4091] 3 Tr 1450-51.
[4092] 4 Tr 3226.
[4093] 4 Tr 3228.

focused reliability analysis, which could be found in the Consumers Energy Reliability Roadmap.[4094]

Mr. Tan commended Consumers Energy for taking the additional steps to understand if vulnerable communities experience certain parts of their distribution grid differently. He stated that these analyses were critical, alongside regression analysis, for the Company to regularly track their reliability progress. He appreciated the efforts of Consumers Energy in proposing its Vulnerable Communities Resiliency Plan; this was a crucial first step towards ensuring vulnerable and EJ communities achieve better reliability in the future.[4095]

Mr. Tan testified that he used regression analysis in Case Nos. U-21389 and U-21585. In these Consumers Energy Rate Cases, he argued that the Company should use regression analysis as another tool to analyze reliability metrics, beyond comparing reliability averages, to better understand how different communities were experiencing outages.[4096] He stated that his regression analysis in those cases used census tract demographic information to compare against Consumers' SAIFI, SAIDI, CAIDI, and Grid Archetype information. He also stated that, to the extent possible, grid characteristics should be included in the regression model. This included average age of poles, wires, recency of tree trimming, and more. By including these grid characteristics, the Company could control for certain variables to better understand if they correlated to

[4094] 4 Tr 3230.
[4095] 4 Tr 3231.
[4096] 4 Tr 3232.

improving or worsening reliability. In Case No. U-21585, he argued that residential disconnections should be analyzed using regression analysis.[4097]

In this case, the Company provided the results of its regression analysis.[4098] He noted that in the more advanced regression models, the results were more nuanced: SAIDI excluding MEDs were worse for census tracts of increasing poverty levels and percentage of unemployed people, when looking at EJ census tracts; feeders serving more urban census tracts tended to have better SAIDI scores than feeders serving more rural areas, while feeders serving EJ census tracts tended to have worse SAIFI scores than those that serving non-EJ tracts.[4099] Regarding residential disconnections, regression analysis showed that increasing BIPOC population was correlated with increasing disconnection rate, even when poverty rate, unemployment rate, and other variables were factored.[4100] Mr. Tan asserted that the Company could be more selective with which regression models to run in future cases recommending that the Company run regression for these reliability metrics: SAIDI with and without MEDs; SAIFI with and without MEDs; CAIDI with and without MEDs; and CELID-5 and -24.[4101]

Regarding the disconnection regression, Mr. Tan asserted that the Company's results substantiate his findings from Case No. U-21585.[4102] He requested that Consumers provide updates on their internal discussions regarding this disconnection regression analysis. He also recommended the Company continue to run regression analyses on residential disconnections to track its progress toward addressing any

---

[4097] 4 Tr 3232.
[4098] 4 Tr 3234.
[4099] 4 Tr 3235.
[4100] 4 Tr 3235.
[4101] 4 Tr 3236-37.
[4102] 4 Tr 3237.

potential inequitable disconnection rates. He further recommended Consumers begin to re-evaluate its disconnection policies. Both Exponent's and the CEO's disconnection regression analyses demonstrated that the Company's disconnection policy disproportionately impacted BIPOC households. Until Consumers proposed a solution to mitigate this disparity, Mr. Tan recommended the Commission issue a moratorium on residential disconnections.[4103]

In response, Mr. Kelly did not express concerns with Mr. Tan's recommendation and noted that the recommendation would help the Company focus on the most salient issues.[4104]

In its brief, the Company expresses no concerns with Mr. Tan's recommendations to focus on a narrower set of reliability metrics using the same independent variables in the next iteration of the regression analysis.[4105]

In its brief, CEO reviews Mr. Kelly's testimony of the Company's regression analysis and CEO witness Tan's testimony on it.[4106] In the end, CEO recommends that the Company "be more selective with which regression models to run in future cases." Specifically, Witness Tan recommended that the Company run: (1) SAIDI with and without MEDs; (2) SAIFI with and without MEDs; (3) CAIDI with and without MEDs; (4) CELID-5 and CELID-24. As a result, CEO recommends the Commission order Consumers to continue to conduct regression analysis with a more limited data set.[4107]

[4103] 4 Tr 3238.
[4104] 3 Tr 1605-6.
[4105] Company brief, p. 436.
[4106] CEO brief, pp. 14-18.
[4107] CEO brief, p. 26.

In the absence of any concerns from the Company, this PFD recommends the Commission direct the Company to run additional regression analyses for these reliability metrics: SAIDI with and without MEDs; SAIFI with and without MEDs; CAIDI with and without MEDs; and CELID-5 and -24 and consider directing the Company to reevaluate its disconnection policies in its next rate case.

In response to the Commission's Order in Case No. U-21389, Mr. Kelly testified that the Company posted interactive GIS maps to its public website that show EJ circuits overlaid with EJ census tracts in the Company's service territory, showing SAIDI and SAIFI by circuit, with and without MEDs, and had created an online form on its public website that allowed interested parties to access GIS data.[4108] Mr. Kelly stated that the Company had not yet completed its Phase II hosting capacity analysis, which would include the hosting capacity of EJ circuits.[4109]

Mr. Cira-Reyes expressed appreciation that the company created a public GIS data map in advance of this rate case. However, he asserted that the GIS data map was not user-friendly and therefore did not serve the purpose of allowing any intervenor or the public to understand easily the company's reliability data. He noted that the GIS data map was a good start but needed considerable improvement to be useful to intervenors and the general public.[4110] Mr. Cira-Reyes recommended that the Commission require Consumers to update the GIS data map's user interface to be easily navigable and understandable to any intervenor and member of the general public who wished to view it. He asserted the website should include, at the very least, a

---

[4108] 3 Tr 1451.
[4109] 3 Tr 1452.
[4110] 3 Tr 2340.

key that explained any acronyms, intuitive map controls, and the ability to do side-by-side comparisons of performance between different circuits.[4111]

Mr. Kelly noted that the current map was largely developed based on Staff feedback to reduce bottlenecks in discovery. Mr. Kelly expressed willingness to make continuous improvements to the public-facing tool but described Mr. Cira-Reyes' recommendation that the map must be easily used by any member of the general public as a very broad and vague target condition.[4112] The Company published its more detailed Phase II HCA map on September 30, 2025, shortly after Mr. Cira-Reyes' testimony was filed. [4113]

In its brief, the Company indicates it is open to considering ways to improve this tool but does not agree that it should be required to make changes based on trying to ensure it is understandable to any member of the general public because of the very broad and vague nature of that target condition.[4114]

In its reply brief, the Company asserts that it has complied with the Case No. U-21389 requirement to make GIS reliability data publicly available, as evidenced by multiple meetings with Staff and the development of a publicly accessible map.[4115]

In its brief, UCC avers that Consumers Energy has failed to provide practical and functional public access to Geographic Information System ("GIS") data consistent with the Commission's Order in Case No. U-21389. Despite creating a public-facing GIS map and an online data request form, the current map is not user-friendly and does not

---

[4111] 3 Tr 2340.
[4112] 3 Tr 1621.
[4113] 3 Tr 1620.
[4114] Company brief, p. 438.
[4115] Company reply brief, pp. 28-29.

enable intervenors or the public to understand or evaluate the Company's reliability performance, particularly in EJ communities. Because meaningful access to GIS data is essential for independent review and transparency, UCC asserts that the Commission should direct Consumers to improve the GIS map's interface and functionality by including clear keys and definitions, intuitive controls, and comparison features.[4116] Providing an online platform without enabling comprehension of the underlying data frustrates the Commission's intent and undermines transparency in assessing Consumers' investments in EJ communities.[4117]

Accordingly, UCC argues the Commission should direct Consumers to revise its GIS data map to meet the standard required by the Commission's Order in Case No. U-21389. To bring the Company into compliance, the Commission should require that Consumers: (1) include a clear key explaining all acronyms and data categories; (2) add intuitive and navigable map controls; and (3) implement functionality that allows side-by-side comparison of reliability performance across circuits. These necessary improvements would impose minimal burden on the Company while transforming the GIS map into a meaningful public access tool, ensuring compliance with Commission's Order in Case No. U-21389 and advancing transparency in the Company's reliability data.[4118]

[4116] UCC brief, pp. 5-6.
[4117] UCC brief, p. 97.
[4118] UCC brief, pp. 98-99.

UCC's reply brief does not specifically address the GIS map, other than to say the Company can and should do more by making GIS data on reliability more accessible to general members of the public.[4119]

In its March 1, 2024 order in Case No. U-21389, the Commission encouraged the parties to collaborate with the Company in the future to make available the locations of Consumers' infrastructure and the types of maps that can be produced,[4120] which the Company did. The Commission also directed the Company to develop "a clear and repeatable process that allows interested parties to request, safely obtain, and use GIS data,"[4121] which the Company did. Having considered the arguments, this PFD finds that the Company could improve further and recommends the Commission direct the Company to make continuous improvements to its public-facing GIS map regarding EJ reliability data, with recommended improvements to include a clear key explaining all acronyms and data categories and intuitive and navigable map controls.

In its mission to provide competitive, affordable rates, Mr. Kelly testified that the Company was seeking federal government funding for reliability and resiliency projects through the IIJA to leverage federal funds to achieve reliability goals.[4122] If the Company was able to obtain federal funding to support distribution infrastructure investment, then the portion of the costs of that infrastructure funded by federal grants would not be passed on to customers.[4123] At the time of this filing, Kelly noted the Company had been selected for four grants related to grid reliability and resiliency, and was in the process

---

[4119] UCC reply brief, p. 10.
[4120] March 1, 2024 order, Case No. U-21389, p. 163.
[4121] March 1, 2024 order, Case No. U-21389, p. 286.
[4122] 3 Tr 1452.
[4123] 3 Tr 1452.

of negotiating with the DOE on the final terms; however, it had not yet received any funding related to the grants.[4124] Mr. Kelly stated that grant recipients must match a varying percentage of the funding awarded to use the grant dollars; as a result, the Company expected to match the federal funds that should be provided for the Section 40101(d) and the two Section 40101(c) grants. However, the full costs for the associated work were included in the capital exhibits, with the portion being provided by the federal government listed as negative dollar amounts.[4125]

Using the 40101(c) funds, Mr. Kelly testified the Company intended to increase sectionalizing on circuits, minimizing the number of customers impacted by a single fault, and constructing new tie lines for circuits currently with no ties to neighboring circuits; ATR loops between these circuits and their new ties would also be added.[4126] Additionally, the Company would use AI modeling in innovative ways to create value for customers in historically disadvantaged communities and in areas of high DER penetration. Data would be obtained through the deployment of 18,000 distributed AI modules on residential electric meters to analyze high volumes of data to detect and classify anomalies, and improve management of distributed assets, which would be particularly valuable in locations with higher EV penetration.[4127]

Using the 40101(d) funds, Mr. Kelly stated that the Company expected to perform rehabilitation work on the Athens HVD line in 2025, and on related nearby LVD circuits in 2026; as well as undergrounding of service drops and upgrades of secondary

---

[4124] 3 Tr 1453.
[4125] 3 Tr 1453-54.
[4126] 3 Tr 1454.
[4127] 3 Tr 1455.

voltage lines in EJ communities.[4128] While these projects were contingent on receipt of the expected funding, the project work was estimated to save 288,000 customer-outage-minutes annually, based on an estimated 80% reduction in outages on the secondary circuits and services feeding homes.[4129] Mr. Kelly stated that the Company would continue to seek the use of a regulatory asset or liability to defer the revenue requirement of IIJA funding expenses above or below amounts included in rates, in accordance with the Commission's guidance in Case No. U-21227, for projects the Company has applied for but has not yet received notification of a selection decision from the federal government.[4130]

Staff witness Schiller addressed the Company's distribution system planning efforts, which the Company referred to as Electric Distribution Infrastructure Investment Plans (EDIIP) or as the Reliability Roadmap.[4131] The MPSC issued guidelines for future DSPs after receiving feedback and comments from participating utilities, including Consumers Energy.[4132] Staff noted that the Company filed an amended version of the 2023 DSP in this case.[4133] The Company included, within Mr. Kelly's testimony, sections of discussion that had been filed previously with the 2023 DSP in MPSC Case No. U-20147, ostensibly to explain the purpose and findings of the prior 2023 DSP.[4134] Ms. Schiller testified that on July 10th, 2025, the Commission issued an order approving Staff's proposed guidance with modifications for future distribution plans, notably after

---

[4128] 3 Tr 1454-55.
[4129] 3 Tr 1455.
[4130] 3 Tr 1456.
[4131] 6 Tr 4291.
[4132] 6 Tr 4291.
[4133] 6 Tr 4292; Exhibit A-129.
[4134] 6 Tr 4292.

this case was filed.[4135] The guidelines informed the Company that it may submit a revised DSP within a rate proceeding under two circumstances 1) significant misalignments between spend categories/allocations following changes in investment strategy or 2) differences between the DSP and the rate case that the utility judges to be significant.

While Ms. Schiller believed the Company was following the best guidance it had at the time for documenting changes in its DSP investment strategy, it should also be noted that the refiled document did not align with the intent of the guidelines and Commission order.[4136] She further noted that the Commission provided additional context in its order by defining "significant" under Section VI as "including areas within a utility's DSP where strategies have changed, where spending levels and/or timing for investments have materially changed, and/or where whole new investment categories are included and discussed" and "foresees as being a rarity as opposed to the normal course."[4137] Ms. Schiller also noted that within the Company's exhibits and proceedings in this case, many projects, programs, and subprograms have changed names and contents. These changes were not always documented and made Staff's comparison between the two documents difficult. In addition, because of the changes documented by Mr. Kelly, many capital costs had changed between the 2023 DSP and the current case. While Ms. Schiller testified that Staff did not oppose the content of these changes necessarily and acknowledged that all plans and forecasts were subject to change, the

[4135] 6 Tr 4292.
[4136] 6 Tr 4293.
[4137] 6 Tr 4293.

recategorization of these changes between the 2023 DSP and the current rate case made these investments very difficult to track between plans and rate cases.[4138]

Ms. Schiller testified that the Commission had previously provided guidance regarding changes to the DSP. Specifically, she stated that the Commission noted several times in its March 21, 2025 Order that "recategorizing or shifting of expenditures from one subprogram to another may lend confusion to the process of identifying historical costs and benefits as well as justifying projected expenditures" and that "simply relabeling or recategorizing capital expenditures from one program or tracking method to another does not provide sufficient evidence to demonstrate the reasonableness and prudence of costs nor the benefits of program expenditures."[4139] The order directed the Company to be clear and do its due diligence to avoid any confusion when discussing historical and planned investments. Given that DSPs discussed planned investments, there was no exception for alignment between the DSP and rate case categories.[4140]

Ms. Schiller noted the Commission disallowed several expenses on such reasoning in that case, and stated that: "…the Commission expects to see additional detail in future electric rate cases regarding line items that have been recategorized, the past spending levels for those line items, how historical spending for any relabeled line items compares to proposed expenditures, and clarity on how these investments deliver value for the company's customers."[4141] Because the new guidelines were approved by the Commission after the Company submitted this rate case, Ms. Schiller indicated that

---

[4138] 6 Tr 4294.
[4139] 6 Tr 4296.
[4140] 6 Tr 4296.
[4141] 6 Tr 4296.

Staff was not recommending any disallowances in this case due to misalignment between the DSP and the rate case.[4142] However, she stated that Staff recommended the Commission recognize such and consider that any costs in future cases that were unable to be reconciled or tracked between the planning efforts and the rate case be disallowed.[4143] She also noted Staff recommended the Commission direct the Company to reevaluate its supplemental rate case filings for future rate cases to align with the July 10, 2025 order in U-20147.[4144]

Ms. Schiller stated that the Company contested Liberty's statement that it had not meaningfully improved its reliability over the past decade and argued that its SAIDI has improved in the three most recent years. It also argued that a five-year average was most appropriate, as it would "limit annual variability."[4145] Ms. Schiller then testified that the Company used a rolling five-year average to create the illusion of a declining trendline over the period 2014-2024. She asserted that using a rolling average line could obscure other trends and as such, the line lagged the current data. She stated Staff used the same data as the Company and ran a typical linear regression trendline to better demonstrate the movement of SAIDI performance in the past decade, using the entirety of the data instead of a five-year average noting that there was a marked lack of reliability improvement.[4146]

Ms. Schiller testified that the Company confirmed through discovery that the model it was using to project potential SAIDI improvements only considered the prior

---

[4142] 6 Tr 4297.
[4143] 6 Tr 4297.
[4144] 6 Tr 4298.
[4145] 6 Tr 4300.
[4146] 6 Tr 4300-1; Exhibit S-19.1.

five years of historical data, and not the larger decade trend presented by Liberty, using this model to create its five-year, seven-year, and ten-year improvement projections.[4147] However, she asserted that these projected glidepaths did not meet the requirements set by the Commission Order in Case No. U-21305 because the Company did not meaningfully examine an extended period to reach second quartile SAIDI performance, and there was no attempt by the Company to show how this extended period could contribute to cost effectiveness, affordability, or decreased rate impacts.[4148] She noted that Staff also took issue with the Company's insistence that the Commission must allow recovery of investments to avoid penalties the Commission itself had set, noting that no "glidepath" shown on the Company's projections would result in a financial penalty.[4149] Staff stated that removal of financial penalties or the acquisition of incentives may be a priority of Consumers, but that did not mean that recovery of related costs was inherently reasonable.[4150]

Ms. Schiller asked that the Commission and the Company give more thought to these potential extended timelines for SAIDI improvements in the Company's next rate case, and Staff recommended the Commission closely scrutinize the models the Company would use to project such investments and compare it to the Company's history appropriately. She stated that Staff also recommended the Commission not allow any spending in future rate cases that was based solely on avoiding financial penalties set by the Commission. Further, she testified that Staff recommended the Commission consider extending the historical data requirements currently presented in

---

[4147] 6 Tr 4302.
[4148] 6 Tr 4302-4.
[4149] 6 Tr 4306.
[4150] 6 Tr 4306.

the guidelines from the July 10th order in U-20147 to ten years, as available, should the Commission choose to revise the guidelines.[4151]

In summary, Ms. Schiller noted that Staff made the following recommendations:

- Request the Company provide a thorough breakdown of the inspection associated costs applied across all capital programs/subprograms, supporting why the costs are appropriately classified as capital instead of O&M with reference(s) to accounting guidance, and amend the classification of those expenditures in the Company's next rate case, where necessary, based on the analysis. In addition, the Commission should require the Company to explain why section 2 under the Operating Expense of USOA was not appropriate for the inspection-related costs of the LVD Lines Demand Failures subprogram and why section 3 under the Electric Plant of USOA was appropriate.
- Require costs to be categorized and similarly trackable between any submitted DSP and any rate case which uses such DSP to justify cost recovery to prove prudency and reasonableness of such costs.
- Require a comprehensible walkthrough of any expense programs, subprograms, and/or categories that have varied between the prior submitted DSP and the ongoing rate proceedings as an exhibit within that rate proceeding. Consider revising the DSP guidelines presented in the July 10th order in Case No. U-20147 to include, where applicable, ten years of historical reliability data, as available.
- Require a method other than the SAIDI performance model used in this case to examine fully potential extended timelines for SAIDI improvements in the Company's

[4151] 6 Tr 4307.

next rate case to be considered reasonable in reference to the June 12, 2025, order in Case No. U-21305.

- Require the Company to assess the cost effectiveness, affordability, and potential rate impact of any SAIDI performance forecast related to the U-21305 order.
- Establish that any expenses in future rate cases based solely on avoiding financial penalties or gaining a financial incentive set by the Commission as imprudent.[4152]

In rebuttal, Mr. Kelly testified that the Company had used the terms Electric Distribution Infrastructure Investment Plan ("EDIIP") and Reliability Roadmap. The Company planned to use the DSP moniker on a go-forward basis, although the three terms – EDIIP, Reliability Roadmap, and DSP – could continue to be understood as interchangeable.[4153] Mr. Kelly rebutted Staff's conclusion that the revised version of the Company's current DSP, filed in the instant case either was not necessary under the terms of the July 10 Order or should not have been filed at all. Mr. Kelly stated that the Company fully intended to comply with all provisions of the July 10 Order, including when DSP revisions in rate cases were warranted, and clarified that, contrary to the statement Staff's testimony, the Company's next DSP would be filed in 2026.[4154] To address Staff's recommendation 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, Mr. Kelly stated that in its 2026 DSP, it would endeavor to present planned investments in a format that allowed

[4152] 6 Tr 4308-9.
[4153] 3 Tr 1566-67.
[4154] 3 Tr 1567.

for easier comparison between the DSP and how costs were presented in rate cases.[4155]

Mr. Kelly also countered Staff's assertion that the testimony on improving reliability was misleading because the Company's use of a five-year rolling average could obscure other trends and that with a rolling average the line lagged behind current data.[4156] Mr. Kelly stated that both Liberty and Staff used 2014 for a baseline, which he averred was arbitrary. He asserted the Company used a rolling average to smooth out annual variability and to reduce the arbitrariness of which dates to use. 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 Staff over any duration would not address annual variability in the same way that a rolling average does. Therefore, he asserted that a rolling average was better for identifying true trends over multiple years,[4157] and asserted that notwithstanding any reliability trends from the 2010s, the Company's reliability in the current decade had clearly improved.[4158]

Mr. Kelly next countered Staff's testimony on whether it had effectively considered seven-year and 10-year glidepaths for SAIDI improvement in addition to a five-year glidepath. Ms. Schiller stated that the Company did not "meaningfully examine" extended glidepaths but simply adjusted its modeling to cover long timeframes and then stated that the Company's analysis did not consider cost effectiveness, affordability, or rate impacts, or consider the Commission's Order related to approaching SAIDI in a

---

[4155] 3 Tr 1567-68.
[4156] 3 Tr 1568.
[4157] 3 Tr 1569.
[4158] 3 Tr 1570.

cost effective manner.[4159] Mr. Kelly responded by stating that it was not clear why it would be inappropriate to evaluate alternate glidepaths by simply adjusting the Company's modeling to target different dates. The Company's model was designed to project a SAIDI performance at a given date when considering spending inputs. If the Company was 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.[4160] He also noted that 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, and that it would certainly comply with the Commission's further direction in future filings.[4161]

Regarding Ms. Schiller's testimony that neither Liberty nor the Commission had mandated that particular programs be cut to create the longer glidepaths, and that the Company could explain why certain programs should not be cut, Mr. Kelly testified that Staff was correct that no such constraints were placed on the development of alternate glidepaths, but that did not mean that the Company would not be effectively constrained. Given the clear direction from Liberty that Line Clearing should be increased, that could not be reduced to create a longer glidepath. Security Assessment Repairs addressed failed components on the system and could not be responsibly deferred. This left Zonal Health Projects, Fractionalization, and ATR Loops as the remaining options for creating a model that delayed the achievement of second quartile SAIDI excluding MEDs until later dates. Mr. Kelly asserted that if the Company delayed

[4159] 3 Tr 1570.
[4160] 3 Tr 1570.
[4161] 3 Tr 1570-71.

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 was to delay reliability improvements to achieve the tradeoff of making fewer capital investments.[4162]

In response to Ms. Schiller's testimony on alternate glidepaths, Mr. Kelly testified that the Company understood the Commission's PBR framework as at least a partial guide for targeted reliability improvements. Through its creation of the PBR framework, the Commission had established certain target reliability, backed by financial consequences for utilities. This framework established the target reliability levels that the Commission expected the Company at a minimum to pursue.[4163]

Mr. Kelly also disagreed with Ms. Schiller's criticism of the Company's modeling and the recommendation that the Commission require a different modeling method to examine potential extended timelines for SAIDI improvements in the Company's next rate case.[4164] He testified that the Company had been and would continue to make model improvements, but it was not realistically possible for the Company to guarantee the accuracy of a predictive model that was 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. Mr. Kelly stated that the Company believed that the

[4162] 3 Tr 1571-72.
[4163] 3 Tr 1572.
[4164] 3 Tr 1572-73.

previous five years were more reflective for both present system and weather conditions.[4165]

Mr. Kelly stated that the Company had historically forecasted SAIDI excluding MEDs, accounting for much of the volatility resulting from weather.[4166] 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, finding that only one utility, DTE, provided a forecast of future performance for All-weather SAIDI. Therefore, if the Commission found that the Company's current SAIDI performance model was inaccurate to the extent that it required a new method to be developed, the Company asked that the MPSC Staff provide publicly available and benchmarkable models from electric utility industry peers that have guaranteed forecasted performance as Staff deemed was necessary for the Company. Furthermore, the Company asked that the Commission provide the Company with at least three years to test and validate an alternative methodology's precision and accuracy.[4167]

In its brief, the Company addresses Staff's comments on the DSP. The Company agrees with Staff's recommendation that costs should be presented costs in a way that make them trackable between the DSP and rate cases.[4168] The Company takes issue with Staff's criticism of its use of a five-year rolling average to present recent SAIDI performance and argues that using a linear regression trend shows a lack of reliability improvement over a full decade. Linear regression does not address annual variability in

---

[4165] 3 Tr 1573.
[4166] 3 Tr 1574.
[4167] 3 Tr 1574-75.
[4168] Company brief, p. 432.

the same way a rolling average does – a rolling average better identifies true trends over multiple years.[4169]

The Company next addresses Staff's argument that it did not "meaningfully examine" extending the time to reach second quartile SAIDI performance. The Company's SAIDI projection model is designed to project a SAIDI performance in the future considering spending inputs, and the Company uses that model to project whether the Company's recommended investments in the Reliability Roadmap put the Company on track to provide second quartile SAIDI excluding MEDs by 2029.[4170] Staff disagrees that slowing investments requires the Company to reduce spending in specific programs, but the only investment categories that can be deferred are Zonal Health Improvements, Fractionalization, and ATR Loops and delaying the glidepath would result in the Company continuing to address deterioration to hold SAIDI roughly steady, but the Company would not invest as much or at all in these programs designed to improve SAIDI.[4171]

The Company argues that the Commission should reject Staff's recommendation to require a different modeling method to examine the extended timelines for SAIDI improvements in the next rate case because it is not necessary and cannot reasonably be accomplished in a short period of time.[4172] The Company argues there is no need to develop a wholly new model and reiterates its testimony on the topic.[4173]

[4169] Company brief, p. 432.
[4170] Company brief, p. 433.
[4171] Company brief, p. 433.
[4172] Company brief, p. 434.
[4173] Company brief, p. 435.

The Company next argues that it would be wholly unreasonable and unfair to deny the Company funding needed to meet reliability targets and then impose financial penalties for failing to meet those targets.[4174] The Company asserts that the Commission should approve investment levels that will allow the Company to avoid a penalty under the Performance Based Ratemaking ("PBR") framework.[4175]

In its brief, Staff recommends the Commission to require costs to be categorized and similarly trackable between any submitted DSP and any rate case which uses such DSP to justify cost recovery and require a comprehensible walkthrough of any expense programs, subprograms, and/or categories that have varied between the prior submitted DSP and the ongoing rate proceedings as an exhibit within that rate proceeding.[4176] No other parties offered rebuttal to Staff's position; therefore, the Commission should adopt Staff's recommendation.[4177]

Staff next recommends the Commission require additional information regarding the Company's projected SAIDI reliability capital investments and perform a detailed review of the compliance with the Liberty expanded timeline recommendations.[4178] Staff also recommends additional assessment the cost effectiveness, affordability, and potential rate impact of any SAIDI performance forecast related to the U-21305 order.[4179] ABATE also concludes that the Commission should demand the Company first demonstrate a clear link between investments and quantifiable reliability

---

[4174] Company brief, p. 434.
[4175] Company brief, p. 434.
[4176] Staff Brief, p. 171.
[4177] Staff brief, pp. 171-72.
[4178] Staff brief, p. 172.
[4179] Staff brief, p. 174.

improvements, with which Staff agrees.[4180] Staff also recommends the Commission establish that any expenses in future rate cases based solely on avoiding financial penalties or gaining a financial incentive set by the Commission as imprudent.[4181] The Company voiced no objections to this recommendation in its rebuttal, and no other parties offered rebuttal to Staff's position.[4182]

In its brief, UCC argues the Company should supplement its regression analysis with a Like-Versus-Like Analysis.[4183] A proper community-based, like-versus-like analysis would compare EJ communities to similarly situated non-EJ communities, that is, urban to urban and rural to rural. Without controlling for urbanization, the Company's conclusion that there are no systemic reliability issues in EJ communities may be unfounded.[4184] UCC asserts the Commission should require the Company to undertake further study and where the analysis ordered by the Commission in U-21585 reveals disparities or contradictory claims and data, the Commission should direct the Company to improve the analysis.[4185]

UCC then argues that the Company should provide more concrete implementation plans for the VCRP.[4186] A community-focused plan necessitates a collaborative approach to ensure that these important investments deliver concrete reliability improvements to the communities that need them the most. A gradual start with a ramp-up in investment after the test year does not preclude detailed planning for

---

[4180] Staff brief, p. 174.
[4181] Staff brief, p. 177.
[4182] Staff brief, p. 177.
[4183] UCC brief, p. 73.
[4184] UCC brief, p. 75.
[4185] UCC brief, p. 75.
[4186] UCC brief, p. 75.

the deployment of the remaining $570 million beyond the $30 million detailed in the Company's initial application. Moreover, funds should be deployed more rapidly, on an accelerated timeline that reflects the urgency of the reliability crisis harming EJ communities documented in the record. For the above reasons, UCC asserts the Commission should require that Consumers provide a more detailed plan for the ten-year VCRP. This plan should include specific investments as currently intended, an accelerated timeline relative to current planning, and performance metrics.[4187]

In its reply brief, the Company states that the Commission should reject the quarterly reporting on project completion rates, spending versus budget, and equity outcomes in the IRM because the IRM reconciliation already addresses these matters.[4188]

This PFD finds that the Company conceded that it would endeavor to present planned investments in an easier format for comparison in subsequent DSPs and rate cases and no other parties offered rebuttal to Staff's position; therefore, Staff asserted the Commission should adopt its recommendation to require costs to be categorized and similarly trackable between any submitted DSP and any rate case which uses such DSP to justify cost recovery and require a comprehensible walkthrough of any expense programs, subprograms, and/or categories that have varied between the prior submitted DSP and the ongoing rate proceedings as an exhibit within that rate proceeding. In its July 10, 2025 order in Case No. U-20147, the Commission stated "DSPs are meant to be fully vetted, executable plans that flow directly into a utility's rate case request, not

[4187] UCC brief, pp. 76-77.
[4188] Company reply brief, p. 28.

an aspirational goal, and alignment between the two filings is necessary for the Commission's accurate evaluation."[4189] Therefore, this PFD recommends the Commission specifically require costs to be categorized and similarly trackable between any submitted DSP and any rate case which uses such DSP to justify cost recovery and require a comprehensible walkthrough of any expense programs, subprograms, and/or categories that have varied between the prior submitted DSP and the ongoing rate proceedings as an exhibit within that rate proceeding. This PFD further recommends the Commission order that any costs in future cases that cannot be reconciled or tracked between the planning efforts and the rate case be disallowed.

As to Staff's recommendation that the Commission require additional information regarding the Company's projected SAIDI reliability capital investments and perform a detailed review of the compliance with the Liberty expanded timeline recommendations, this PFD is only partially persuaded by the arguments presented. The Company's analysis is lacking as to how an extended timeline could contribute to cost effectiveness, affordability or decreased rate impacts; however, the Company's modeling has predicted SAIDI performance with a total net variance of only seven SAIDI minutes over the last five years. Additionally, the Company's assertion that adopting the Liberty audit recommendations constrained its maneuvering has some merit. While Staff points to the impact of PBR on the Company's selection of the five-year glidepath, it does not appear to be the sole reason for selecting that glidepath. Line clearing does have a point of diminishing returns where other investments in the system to improve reliability will be necessary. Therefore, this PFD recommends the Commission (1) direct

[4189] July 10, 2025 order in Case No. U-20147, p. 21.

the Company to demonstrate a clear link between investments and quantifiable reliability improvements; and (2) assess cost-effectiveness, affordability, and potential rate impact of any SAIDI performance forecasts related to the U-21305 order – to include the extended glidepath options.

The Company asserts it used a rolling average to smooth out annual variability and to reduce the arbitrariness of which dates to use, whereas Staff uses a linear regression over 10 years. This PFD finds that both positions have merit when evaluating data. Rolling averages smooth out volatile data, longer time frames smooth the curves with shorter periods showing more response to recent changes; however, like all types of data manipulation, the variations are capable of either bringing issues to light or hiding inconvenient issues. Both Staff and the Company have reasonable arguments supporting their position. Therefore, this PFD recommends the Commission consider revising the DSP guidelines presented in the July 10th order in Case No. U-20147 to include, where applicable, ten years of historical reliability data, as available.

Staff recommended that the Commission establish that any expenses in future rate cases based solely on avoiding financial penalties or gaining a financial incentive set by the Commission be considered imprudent and disallowed.[4190] While the Commission's PBR framework does serve as a partial guide for targeted reliability improvements backed by financial consequences for utilities that fail to meet the minimum requirements, expenditures made ***solely*** to avoid penalty or receive an incentive would neither be reasonable nor prudent. The Company voiced no objections to this recommendation in its rebuttal, and no other parties offered rebuttal to Staff's

[4190] 6 Tr 4308-9.

position. Therefore, this PFD recommends the Commission establish that any expenses in future rate cases based ***solely*** on avoiding financial penalties or gaining a financial incentive set by the Commission are imprudent.

Staff recommends the Commission require a method other than the SAIDI performance model used in this case to examine fully potential extended timelines for SAIDI improvements in the Company's next rate case. The Company countered, asking Staff to provide publicly available and benchmarkable models from electric utility industry peers that have guaranteed forecasted performance deemed necessary and at least three years to test and validate the alternative methodology's precision and accuracy[4191] if the Commission concurred with Staff. There is nothing in the Commission's June 12, 2025, order in Case No. U-21305 to suggest the Commission would be in favor of the Company abandoning its current SAIDI performance model, rather the Company was asked to look at achieving its SAIDI performance goals in a cost-effective manner.[4192] Therefore, this PFD recommends the Commission direct the Company to provide a comparison of its actual reliability performance to its reliability impact projections based on forecasted distribution capital program spending and a rate impact analysis for meeting its reliability goals in five, seven, and 10 year timeframes,[4193] including an assessment of the cost effectiveness, affordability, and potential rate impact of any SAIDI performance forecast in its next rate case.

[4191] 3 Tr 1574-75.
[4192] June 12, 2025 order in Case No. U-21305, p. 18.
[4193] June 12, 2025 order in Case No. U-21305, p. 17.

Considering the above, this PFD further recommends the Commission direct the Company to reevaluate its supplemental rate case filings for future rate cases to align with both the July 10, 2025, Order in U-20147 and the above recommendations.

D. Capital Spending Overview

Mr. Kelly testified that the Company was committed to making investments in its distribution system to ensure they would deliver clear and cost-effective customer benefits, using “least-cost, best-fit” analysis for traditional investments on the distribution system.[4194] When an asset has failed, the Company used the least costly solution; however, the Company has used more extensive benefit-cost analyses for some non-traditional investments.[4195] Kelly stated the Company defined “traditional” distribution investments as investments in components of lines (such as poles, pole tops, conductor, and certain devices), substation infrastructure, and other related items, across a variety of investment programs. Conversely, he stated the Company defined “non-traditional” distribution investments as those in newer technologies, such as those covered in Grid Automation, or in certain pilot programs.[4196] The least-cost, best-fit analyses ensured investments are both cost-effective and meet the necessary functionality and capability requirements; however, those analyses are not necessarily used to rank and prioritize projects against one another. Once assets have been prioritized and the Company has determined where work is needed, least-cost, best-fit was used to select the type of project to execute in that location[4197]

[4194] 3 Tr 1457.
[4195] 3 Tr 1457.
[4196] 3 Tr 1457.
[4197] 3 Tr 1458.

For many larger projects, Mr. Kelly explained that the Company used a more formal process to compare proposed electric distribution investment against alternatives, developing a "concept approval" to test and demonstrate why the selected project was reasonable and prudent, ensuring strong and robust justification for selected electric distribution projects.[4198] Once the problems or needs were identified, the planning engineers developed a list of alternative solutions, with costs, benefits, and intangible considerations developed. The alternatives were then compared against each other, and the planning engineers identified a selected alternative that yielded the best fit and was intended to produce the maximum benefit at the least cost.[4199] The final step of the process was to document all the information in a concept approval document that was routed through management for approval.[4200] Mr. Kelly stated that the concept approval process provided a rigorous approach and governance structure to identifying problems and needs, alternative solutions, and recommended alternatives. It also provided for exceptional peer review and management oversight to ensure the Company's investment plans were well justified, reasonable, and prudent for customers.[4201]

Mr. Kelly stated the Company's capital investment programs responded to demand-driven, customer-driven, or other emergent needs. While not strictly "unplanned," the Company forecasted the number of new business services that would be requested in the future based on historical service levels and projected growth rates and then applied a unit cost to these expected requests to develop a forecasted level of

[4198] 3 Tr 1458-59.
[4199] 3 Tr 1459-60.
[4200] 3 Tr 1460.
[4201] 3 Tr 1462.

spending. These unplanned programs consisted of New Business, Demand Failures, and Asset Relocations.[4202] Kelly noted the Company also planned investments further in advance to proactively improve the grid through reliability improvement projects, capacity upgrades, and investments in new tools and technology. These programs consisted of Reliability, Capacity, Electric Other, and Technology.[4203]

Descriptions of distribution projects for the bridge period and test year include scope, cost, location, benefit type, and benefits.[4204] Benefit types included Customer-outage-minutes and Customers impacted. Mr. Kelly testified that Customer-outage-minutes (sometimes referred to as customer minutes interrupted or "CMI") was a mathematical product of the number of customers that experienced an extended outage of electrical service, and the duration in minutes of that outage.[4205] A reliability project would reduce this number by reducing the probability of failure leading to an outage, the duration of the outage, and/or the number of customers impacted by the failure and subsequent outage. Using the CMI, the benefit of a distribution reliability project could be quantified.[4206] Mr. Kelly asserted that while there may be an indirect connection between customer-outage-minutes avoided and SAIDI, they were two separate things and should not be conflated.[4207] Mr. Kelly testified that customers impacted was the number of customers who were served by an asset or project and therefore would

[4202] 3 Tr 1466-67.
[4203] 3 Tr 1467.
[4204] 3 Tr 1468.
[4205] 3 Tr 1468.
[4206] 3 Tr 1468-69.
[4207] 3 Tr 1469.

experience an outage of electrical service if this asset were to fail or would realize a benefit to reliability with its improvement.[4208]

While the Company attempted to project investment needs for the New Business, Demand Failures, and Asset Relocations programs, the largest factors influencing expenditures in these programs are externally driven. As a result, Mr. Kelly testified that the Company requested that it be allowed to continue to defer the revenue requirement for any capital spending for these programs above what was included in rates, if the spending exceeds what the Commission approves in this case. According to Mr. Kelly, the Company would agree to the same stipulations the Commission approved for deferred accounting treatment for these programs in Case No. U-21585. First, that the Company spend the full amounts approved by the Commission in the Line Clearing Program, which the Company requested that the threshold be set on the "baseline" Line Clearing O&M expenses of $164.446 million, supported by Ms. Stewart.[4209] Mr. Kelly asserted that if deferred accounting was not authorized for any spending in New Business, Demand Failures, and Asset Relocations that exceed what the Commission approved, then the Company would be exposed to financial risk if increased investment needs materialized in those programs.[4210] Since the Commission did not always approve all of the Company's projected investment amounts in these programs, deferred accounting worked to provide for recovery of externally-driven investments that

[4208] 3 Tr 1470.
[4209] 3 Tr 1470; 3 Tr 2218.
[4209] 3 Tr 1470; 3 Tr 2218.
[4210] 3 Tr 1471.

must be made and ensured the Company did not need to reduce investments in other programs that focused on proactively improving customer reliability.[4211]

E. Historical System Performance

To evaluate electric distribution system performance, Mr. Kelly testified that the Company considered several reliability metrics, with SAIDI being the most prominent. Other key reliability metrics measured and tracked by the Company include SAIFI, CAIDI, and CEMI.[4212] The Company provided the MPSC annual performance information related to SAIFI, CAIDI, and SAIDI with and without MEDs, on a rolling five-year average, using the industry standard IEEE method of calculation.[4213] According to Mr. Kelly, the year-over-year variation was driven in part by the number of MEDs each year, as any MED was likely to result in more customer outages than on a normal day. Storms in March 2017, July 2019, June 2020, August 2021, and February 2023 all exceeded this threshold, and all translated into large increases in customer interruption minutes, driving the higher annual SAIDI totals in those years. Additionally, he noted that the number of MEDs had been consistently higher since 2017, serving as an indicator of worsening weather and system deterioration.[4214]

Mr. Kelly asserted that to achieve the MPSC's Service Quality and Reporting Standards goal for CEMI-4, the requested funding for the Repetitive Outage Program was needed.[4215] He also testified that the Company monitored wind speed data from 21 different official National Weather Service stations in Michigan, and noted that wind

[4211] 3 Tr 1472.
[4212] 3 Tr 1479.
[4213] 3 Tr 1479.
[4214] 3 Tr 1483.
[4215] 3 Tr 1483.

speeds across the system have increased in severity.[4216] Mr. Kelly concluded that, as highlighted by the data, as Michigan saw increasingly extreme weather, the electric distribution system needed to be hardened against that weather to improve resiliency.[4217]

In his testimony, CUB witness Richard J. Bunch stated that it was fair to expect the Company to deliver electricity at similar prices and with similar reliability as utilities in nearby states, but the Company's customers are already paying more while getting worse service.[4218] In competitive markets, companies would not expect approval for increased capital while simultaneously presenting substantially poorer performance metrics relative to their industry peers.[4219] Mr. Bunch stated that the Company should recover reasonable and prudent costs; however, granting substantial rate increases to help the Company catch up to service reliability benchmarks, when its rates were already high, was unreasonable.[4220] According to Mr. Bunch, it would be unfair to charge today's customers the full cost of investments that should have been made in the past, on top of current investments.[4221] He and Mr. Jester then recommended that certain distribution surge expenses should not be recovered as O&M costs or added to rate base but should rather be held as regulatory assets to be considered for future securitization subject to prudency review.[4222] Mr. Bunch then recommended that the Commission direct the Company to review its allocators from a cost-causation

---

[4216] 3 Tr 1487.
[4217] 3 Tr 1489.
[4218] 6 Tr 4022.
[4219] 6 Tr 4022.
[4220] 6 Tr 4023.
[4221] 6 Tr 4023.
[4222] 6 Tr 4023.

standpoint, incorporating its analysis of the benefits of these investments, and either propose adjustments or justify the status quo as part of its next rate filing.[4223]

Mr. Bunch also recommended that the Commission approve surge spending on certain reliability programs identified as priorities in reports by the Liberty Consulting Group summarizing its audit of Consumers' distribution system. Witness Bunch asserted that the Company should recover these costs, but in such a way as to minimize the rate impact of remedial work on today's customers and to recognize that the Company bears some responsibility for the financial and service-quality impacts of catching up on backlogged work.[4224] Mr. Bunch stated that the Company's proposed costs and allocation would result in residential rates increasing by over 13%. A growing number of customers were already struggling and the Company's rates were already high and have recently risen faster than inflation.[4225] Mr. Bunch also stated that the Commission should take steps to ensure that reliability costs were allocated equitably among rate classes and that the way those costs are recovered was equitable.[4226]

Mr. Bunch recommended the Commission approve backlogs in tree trimming/vegetation maintenance and pole replacements for surge spending and hold other reliability investments at PAI-adjusted current levels.[4227] Mr. Bunch suggested that focusing on the backlogged tasks first will make it easier to determine what additional reliability actions may be needed next, after the proverbial dust settles.[4228]

[4223] 6 Tr 4024.
[4224] 6 Tr 4048-49.
[4225] 6 Tr 4049.
[4226] 6 Tr 4049.
[4227] 6 Tr 4049.
[4228] 6 Tr 4049.

In rebuttal, Mr. Kelly averred that it was 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 was not recovered in a single year.[4229] Mr. Kelly also expressed concern that other than line clearing and LVD pole replacements, Mr. Bunch believed all other reliability investments should be held at "PAI-adjusted current levels," referring to a methodology that he had developed to index spending levels to inflation.[4230] Mr. Kelly stated that it was 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. Mr. Bunch's proposal would simply cause deterioration in the system to rapidly accelerate.[4231] Mr. Kelly also asserted that Mr. Bunch's recommendation was vague because it was not clear which investments he intended to include in this recommendation. Mr. Kelly disagreed that the Company should invest in a very limited range of work, and with the implication that the Company could not tell which reliability investments were beneficial.[4232]

In its brief, the Company addresses Mr. Bunch's recommendation to focus reliability increases on backlogged tasks to make it easier to determine the additional reliability actions that may be needed – inferring the Company cannot presently determine which reliability investments are beneficial. Mr. Bunch's assumption is incorrect. The Company has documented the reliability benefits of many types of

[4229] 3 Tr 1613.
[4230] 3 Tr 1613.
[4231] 3 Tr 1614.
[4232] 3 Tr 1614.

investments, in particular Zonal Health Improvements, and has presented that evidence in this case.[4233]

In its brief, MNSC relies on the parties' testimony and argues that the Commission should order regulatory asset treatment and subsequent securitization of the Company's above-baseline spending to ramp up forestry work and LVD pole replacements.[4234]

After reviewing the testimony of Mr. Bunch and the Company, this PFD is not persuaded by the recommendation to focus on backlogged tasks – whether the Company undertakes beneficial reliability investments or not, it is still in the best position to determine which reliability investments are beneficial. Therefore, this PFD recommends that the Commission reject Mr. Bunch's recommendation to focus reliability increases on backlogged tasks to make it easier to determine the additional reliability actions that may be needed.

Mr. Albers testified on behalf of the Michigan Energy Innovation Business Council ("Michigan EIBC"), the Institute for Energy Innovation, and United, collectively referred to as "MEIU."[4235] Mr. Albers noted that because of long lead times associated with obtaining critical equipment necessary for accomplishing interconnections, deployment of new DER, EV charging stations, and generation resources could be delayed. Such delays not only impede the goals of utilities and developers but could hamper Michigan's ability to meet its statutory clean energy standard of 80% between

[4233] Company brief, p. 437.
[4234] MNSC brief, p.148.
[4235] 6 Tr 4223.

2035 and 2039 and 100% by 2040. The initial 80% standard is only 10 years away.[4236] Mr. Kelly addressed the Commission's direction to identify equipment generally needed for DER and EV interconnections that currently have a long lead time for procurement. Mr. Albers testified that Mr. Kelly's testimony satisfied the Commission's direction to "identify equipment generally needed for DER and EV interconnections, such as transformers, that currently had a long lead time for procurement." Mr. Albers went on to note that it was less clear whether the remainder of what Mr. Kelly described satisfied the direction to "propose a plan for maintaining an adequate inventory of that equipment to support future development."[4237] Mr. Albers recommended that the Commission require Consumers to 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 was available to the utility for projects that it initiates.[4238]

Mr. Albers followed up his direct testimony with rebuttal testimony of Mr. Kenworthy and Mr. Boehnke. He generally agreed with both Mr. Kenworthy's and Mr. Boehnke's recommendations regarding developing a VPP program in conjunction with a distributed energy resources management system ("DERMS").[4239]

In rebuttal, Mr. Kelly noted that the Company already did 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, Mr. Kelly stated that the Company created and

[4236] 6 Tr 4227.
[4237] 6 Tr 4229.
[4238] 6 Tr 4231.
[4239] 6 Tr 4237.

scheduled work orders in the order that the interconnection approval process was completed. It was important to clarify that the Company did not sell inventory to third-party customers who own and maintain their own equipment. He noted that the Company interpreted Mr. Albers' proposal to mean only projects initiated by third parties, not projects conducted by third parties.[4240]

In its brief, the Company argues that Mr. Albers' recommendation reflects the Company's current practice.[4241]

In its brief, MEIU relies on the parties' testimony and argues that because Mr. Albers' recommendation is not opposed by Consumers, the Commission should recognize in its order that Consumers has acknowledged that the practice of making equipment inventory available to support third-party-initiated projects on the same basis as Company-initiated projects is appropriate and direct the Company to continue to do so.[4242]

This PFD notes that the Company did not specifically object to MEIU's recommendation because it reflects Company practice; therefore, this PFD recommends the Commission recognize the Company's practice of making equipment inventory available to support third-party-initiated projects on the same basis as Company-initiated projects is appropriate and direct the Company to continue to do so.

F. Distribution Deferral Mechanism

[4240] 3 Tr 1623-24.
[4241] Company brief, p. 439.
[4242] MEIU brief, pp. 28-31.

Mr. Daly supported Consumers' requested continuation of the Distribution Deferral Mechanism in the test year, with the calculation of the $24.3 million deferral and straight-line amortization of the associated regulatory asset balance.[4243]

Mr. Evans testified that Staff believes the $24.3 million deferral is reasonable and prudent.[4244] However Staff recommended continuing the following conditions approved by the Commission in Case No. U-21585:

> 1) that Consumers provide a list of sub-programs and investment categories within each of the five programs of New Business, Demand Failures, Asset Relocation, Reliability, and Line Clearing and communicate any significant changes to Staff while the changes are being planned and prior to their implementation;
>
> 2) that Consumers provide quarterly spending reports in each of the five programs throughout the test year and notify Staff of any anticipated spending above 110% of the approved amount, including an explanation for the overspend;
>
> 3) that Consumers spend the full amounts approved by the Commission in the Line Clearing programs and if the full amount is spent, deferred accounting treatment shall be authorized for both the overspend and the underspend, and it if is not, deferred accounting treatment shall only be authorized for the underspend; and
>
> 4) if deferred accounting treatment is sought again in the future, it must be requested in a future rate case.[4245]

Mr. Kelly testified in rebuttal that Consumers appreciates Staff's continued support of the deferral mechanism and finds that Staff's conditions continue to be reasonable.[4246] Both respective briefs recommend approval of the continuation of the distribution deferral subject to Staff's four conditions. As there is no apparent opposition,

---

[4243] 3 Tr 1074-1075; Ex. A-84.
[4244] 6 Tr 4446.
[4245] 6 Tr 4447, citing Case No. U-21585. Order, March 21, 2025, page 381-382.
[4246] 3 Tr 1575-1576.

this PFD recommends approval of the requested continuation of the Distribution Deferral Mechanism subject to Staff's four conditions as listed above.

G. Low-Income Assistance Programs

Ms. Byrom provided testimony regarding the Energy Assistance Team within the Billing and Payment expenditures of Credit and Assistance of CX&O. The team administers the Company's assistance plans, including the Consumers Affordable Resource for Energy (CARE) program, providing LI customers with either a one-time bill assistance payment or ongoing enrollment in an Affordable Payment Plan (APP), and providing reduced monthly bills and payment of arrears over time. The team obtained $8.8 million of affordable payment plan (APP) specific assistance, and $7.2 million in one-time assistance, for customers requested through the Michigan Energy Assistance Program (MEAP).[4247]

In addition to this avenue of assistance, Ms. Byrom presented the LMI Enhancement project, discussed previously in this PFD.[4248] The Company is also proposing to increase the LIA credit from $30 per meter to $42 per meter for 2026, and to increase the number of customers receiving the credit to 6,200, with 1,000 customer per year increases through 2029.[4249] Finally, the Company proposes a tariff change to increase eligibility for the Shut Off Protection Plan (SPP).[4250]

Mr. Cira-Reyes for UCC provided further detail regarding Consumers' bill assistance programs for LI households: the CARE Flat Rate, which ended new enrollments in 2024; the CARE Modified Budget (MB) program, which offers to eligible

[4247] 3 Tr 967.25-967.26.
[4248] 3 Tr 967.26-967.38.
[4249] 3 Tr 967.26, 967.38-967.39.
[4250] 3 Tr 967.26.

households a 24-month payment plan that adjusts every six months, while providing arrearage forgiveness of up to $3,000; the LIA program, currently offering $30 per month credits to up to 4,200 customers, with the credit increasing to $55 per month to accommodate 8,200 customers by 2029; and the RIA, which provides an $8 per month RIA electric credit.[4251]

According to Mr. Cira-Reyes, these programs are insufficient and can result in customers receiving less assistance if they are enrolled in multiple programs while CARE program support is used to cover agency costs when they are also enrolled in the LIA program.[4252] Approximately 83% of LI households receive the RIA credit. Per Mr. Cira-Reyes, the proposed rate increase in this case would exceed the credit, and there is no explanation for why all LI households do not receive the credit.[4253] Only one in six LMI customers are enrolled in a Consumers' assistance program, and many who are enrolled do not receive benefits until they are already in crisis.[4254] Mr. Cira-Reyes recommended that Consumers be required to perform a regular affordability analysis, and he requested that the Commission scrutinize Consumers' requested rate increase, limiting it as much as possible due to affordability concerns.[4255] This testimony was reflected in UCC's brief.[4256]

Ms. Byrom testified that the Company does not have an accurate method for calculating individual customers' energy burdens. Instead, Consumers and assistance agencies work with individual customers to evaluate needs, present program options,

---

[4251] 3 Tr 2307-2309.
[4252] 3 Tr 2308-2309, 2312-2313.
[4253] 3 Tr 2309-2310.
[4254] 3 TR 2310.
[4255] 3 Tr 2321.
[4256] UCC brief, 20-31.

and facilitate customers in making the best decisions for their needs.[4257] She did not agree with Mr. Cira-Reyes' characterization of multiple credits resulting in a higher customer bill than would have been received without assistance. She took the position that, when multiple available programs are used, the customer's bill is less expensive per month.[4258] Furthermore, she noted that Consumers has expanded its assistance to include moderate income customers with energy insecurity, focusing on energy efficiency.[4259]

UCC's brief asserts in response that, in 2020, nearly 10% of Consumers' customers, approximately 160,000, were between 150% and 200% of the federal poverty level (FPL). Based on this UCC contends that Consumers' focus on reducing energy usage, rather than affirmative payment assistance, unfairly minimizes the severity of the issue. UCC contends that nearly 95% of these customers have an unaffordable energy burden at all times.[4260]

Generally, Mr. Cira-Reyes and Ms. Williams presented testimony regarding the difficulties of customers in accessing the Company's Customer Assistance Programs, which was fleshed out in UCC's brief.[4261] Mr. Cira-Reyes outlined energy affordability, energy insecurity, and energy burden, particularly in relation to LMI households and BIPOC communities.[4262] He noted that there are "some assistance programs to aid with financial challenges," but that these are difficult to access, insufficient to meet current

---

[4257] 3 Tr 967.71.
[4258] 3 Tr 967.72.
[4259] 3 Tr 967.73.
[4260] UCC brief, 27-29.
[4261] 3 Tr 2310-2312, 2389-2391. UCC brief, 29-31.
[4262] 3 Tr 2293-2300.

needs, and outpaced by assistance demands.[4263] He recommended that the Commission direct the Company to formally analyze customer affordability, given that the Company already collects information regarding energy affordability for individual households.[4264] Again, this testimony is reflected in UCC's brief.[4265]

Ms. Williams recommended rearrangement of program administration to make programs more reliable and easy to navigate, with live customer assistance and different forms of communication with graphics available, and with payment assistance options crafted to ensure energy affordability.[4266] Ms. Williams opined on the Company's color-coded shutoff notices, advertising a family's financial struggles, indicating that she heard a consistent complaint from families that "the utility will make it very easy to reach you when they want payment, but when you are heading toward shutoff and might need help accessing assistance programs, there's no proactive outreach."[4267] She also outlined how difficult it is to reach a human being at Consumers and get meaningful answers, and she outlined Consumers' failures in community engagement.[4268] UCC's brief adds that the Commission should require transparent reporting and accountability measures regarding customer communications, and should also direct Consumers to work with environmental justice organizations in engaging with the community.[4269]

[4263] 3 Tr 2300-2301
[4264] 3 Tr 2313-2316.
[4265] UCC brief,
[4266] 3 Tr 2391-2392.
[4267] 3 Tr 2392-2394.
[4268] 3 Tr 2396-2400.
[4269] UCC brief, 6-7.

Ms. Byrom responded that the LMI Customer Support Enhancement project was geared at helping to resolve some of the accessibility concerns presented by Mr. Cira-Reyes and Ms. Williams, adding that relevant information is also available on Consumers' website. She stated that the Company balances investment into infrastructure, safety, and reliability with the need for assistance, working within current funding and administration structures with community agencies and assistance providers to actually provide available assistance.[4270] To address the concerns regarding unreliability and navigation difficulties, the Company makes program details available on its website, engages in digital marketing to eligible customers, and works with agencies to make enrollment as easy as possible. Many of the issues UCC's witnesses identified, per Ms. Byrom, are outside of the Company's direct control because the Company does not own or administer the actual assistance programs. Ms. Byrom then outlined many proactive steps that Consumers takes to identify and communicate with LMI customers for the purpose of connecting customers with assistance.[4271]

In response to Ms. Williams' suggestions regarding improving proactive consumer outreach,[4272] Ms. Byrom highlighted that there is a dedicated staff of community outreach partners working exclusively with MEAP agencies, and that Consumers' Community Affairs, Energy Assistance, and EWR teams actively attend community events to directly engage with customers and community partners. The Company also uses census tract and ALICE data, along with arears analysis, to identify

[4270] 3 Tr 967.65-967.66.
[4271] 3 Tr 967.66-967.68.
[4272] 3 Tr 2399-2400.

LMI areas with high need and untapped eligibility in order to target education and intervention efforts.[4273] Consumers also offers training and continued contact information to interested assistance agencies as well as standardized language and literature.[4274]

In relation to Ms. Williams' concerns regarding language and communication barriers, such as those due to age and disability, Ms. Byrom indicated that the Company offers a Spanish language option through the Company's Contact Center. She otherwise left unaddressed concerns that those with disabilities may have difficulties with Company communications. She did, however, indicate that expanding language options beyond offering a Spanish-language option "is not feasible and would not be cost effective."[4275]

Consumers, in its brief, reiterates that the LMI Simplified Enrollment flow is intended to assist customers in finding programs that best meet their needs. The Company's website also has information on its website detailing assistance programs, including eligibility requirements and agency contact information. Consumers also engages in digital marketing to eligible customers.[4276] Consumers further repeats that the steps necessary to enroll in payment assistance programs are "part of the state level process to ensure compliance with income requirements."[4277]

[4273] 3 Tr 967.68-967.69.
[4274] 3 Tr 967.68-967.69.
[4275] 3 Tr 967.69.
[4276] Consumers brief, 441.
[4277] Consumers brief, 441-442.

In relation to Ms. Williams' testimony regarding inconsistent communication and lack of effective proactive consumer outreach and engagement,[4278] Consumers agrees that work with community leaders and assistance organizations "is an effective option," and that this is an active avenue of engagement for the Company.[4279] The Company also highlights the dedicated staff working with MEAP agencies, outreach energy assistance staff, and other programs prioritizing direct engagement with customers and community groups.[4280] Because the Company does not own or administer the assistance programs, Consumers rejects UCC's suggestion that enrollment be made automatic without applications, but indicates that it is committed to improving customer experience through the LMI project and proactive marketing.[4281] Additionally, the Company cannot automatically enroll customers because expansion of existing programs would burden existing customers to subsidize the expansion, and because programs delaying shut offs preclude customers from receiving State Emergency Relief (SER).[4282]

Consumers' reply addresses the request for affordability analysis by indicating that it already considers affordability in its filing. The Company asserts that the Commission is not bound to a rate-setting formula. It also asserts that the Commission should not require an affordability analysis because this will have unclear results based on incomplete information.[4283]

[4278] 3 Tr 2396-2398.
[4279] Consumers brief, 442.
[4280] Consumers brief, 442.
[4281] Consumers brief, 442-443.
[4282] Consumers brief, 443.
[4283] Consumers reply, 29.

As discussed below, this PFD rejects the recommendation for automatic program enrollment because to do so might jeopardize customer participation in a more appropriate form of utility relief. Furthermore, while this PFD encourages Consumers to take to heart Ms. Williams' comments about Company position and prominence at community events, making certain that both the Company's presence and information are visible and engaging, the Company's outreach, while not necessarily optimal in reaching those in need, cannot be said to lack reasonableness or prudence. Additionally, it is not clear what improvements could be made to assist disabled and elderly people in accessing information from Consumers. In sum, this PFD does not formally adopt the UCC witnesses' recommendations. Nevertheless, this PFD recommends that Consumers increase the color graphics and increase the font size in at least some of their handouts at community events to make them easier to read.

Beyond these general matters, some concerns with individual programs and recommendations are discussed below.

1. Shut-off Protection Plan

To address the issue of an estimated 26% of customers who are moderate-income level and payment challenged, Ms. Byrom indicated that the Company is proposing a tariff language change [set forth in Exhibit A-16, Schedule F-5] and changes to eligibility for the SPP. Specifically, Consumers is increasing eligibility to 400% or less of the federal poverty level, to better address moderate income or Asset Limited, Income Constrained, Employed (ALICE) customers.[4284] The current SPP is available for customers who are at or under 200% of the federal poverty level, but the

[4284] 3 Tr 967.40-967.41.

Company is proposing to increase the federal poverty guidelines eligibility cap to offer more options to 700,000 moderate income customers.[4285] Consumers' brief repeats this testimony, noting that the altered tariff language is found in Exhibit A-16.[4286] These changes appear to be unopposed, and this PFD recommends their approval.

2. Winter Protection Plan (WPP)

Ms. Williams recommended automatic enrollment in the WPP and other assistance plans without an application. Her concern was that many families in crisis do not know about the WPP until they are facing a shutoff.[4287] Being in shutoff status can prevent online or phone payments, requiring a physical trip to a payment location, thereby disadvantaging the elderly, the disabled, and those without reliable transportation.[4288]

Ms. Byrom responded that requirements exist at the state level regarding customer qualifications for energy assistance, and expansion to additional customers would burden existing customers to subsidize the cost of expansion. Additionally, programs delaying shut offs preclude those customers from receiving State Emergency Relief (SER).[4289] Instead, Consumers proactively markets eligible programs in advance of customer crises. Ms. Byrom also indicated that the Company automatically enrolls customers who receive the home heating credit into the WPP, and some customers have called to disenroll, displeased they were not given a choice regarding whether to

[4285] 3 Tr 967.40-967.41.
[4286] Consumers brief, 443.
[4287] 3 Tr 2394-2395.
[4288] 3 Tr 2395-
[4289] 3 Tr 967.70.

sign up. Finally, the WPP only helps to prevent shutoffs during cold months, often resulting in larger account balances; it does not address long-term affordability.

As a result, Consumers states that it prioritizes more sustainable plans like the CARE program.[4290] Consumers partnered with the Essential Needs Task Force to guide outreach and funding strategies in order to connect customers with needed assistance.[4291] Consumers' brief adopts this testimony.[4292]

Because the WPP is effectively a forbearance plan that some customers may not want, this PFD recommends against automatic enrollment. The example that a customer may be seeking SER and may not wish to lose eligibility through WPP enrollment is compelling.

Mr. Cira-Reyes, however, testified regarding extreme summer weather, and LMI communities maintaining homes at unsafe temperatures due to high cooling costs.[4293] He noted that Case No. U-20140 has been opened to discuss extreme weather disconnection policies. However, he recommended that the Commission create an interim heat extreme weather policy in this case for events where time and weather advisory protections extend past the extreme heat event if Case No. U-20140 does not yield a policy before summer 2026.[4294] UCC's brief reiterates these points, stressing that this is an urgent concern that cannot wait for the discussion of extreme weather disconnection policies to play out in Case No. U-20140. UCC discusses using different methods to determine an extreme weather event, used by different utilities, including

---

[4290] 3 Tr 967.70-967.71.
[4291] 3 Tr 967.70-967.71.
[4292] Consumers brief, 444.
[4293] 3 Tr 2301-2303.
[4294] 3 Tr 2303-2304, 2321-2322.

use of National Weather Service advisories as a benchmark for when an extreme weather event is called.[4295]

In sum, UCC asserts that Consumers should be prohibited from disconnecting residential service when either the forecasted temperature will reach 90 degrees Fahrenheit or the National Weather Service issues a heat advisory. Disconnections should be restricted to at least 24 hours before and after extreme heat events, as well as weekends and holidays, and disconnections should be prohibited during the months of June, July, August and September.[4296] UCC further recommends this prohibition on disconnections for June through September should be issued, even if the Commission chooses to wait until Case No. U-20140 yields results.[4297]

When presented with the same arguments in Case No. U-21585, the Commission indicated that the discussion of extreme weather condition policies should be conducted in Case No. U-20140. This PFD recommends the same.

3. Percent of Income Payment Program (PIPP)

Although recognizing that the Commission has rejected it in the past, Mr. Cira-Reyes maintains that a percentage of income payment plan (PIPP) model would be more efficient than current assistance programs in providing affordable electricity to LMI customers.[4298] Mr. Cira-Reyes further contends that Consumers has not explained why, after a 2 year PIPP pilot program that ended in March 2025, the Company did not implement a full-scale PIPP program for LMI customers. He adds that the Company's assertion that the costs outweighed the program benefits discounted that PIPP

[4295] UCC brief, 87-94.
[4296] UCC brief 94-95.
[4297] UCC brief, 95.
[4298] 3 Tr 2310-2320.

addressed the shortcomings of the existing programs.[4299] He noted that DTE recently found a similar program to be sustainable and administrable, and that customers reported a more positive customer experience under Consumers' PIPP than with the CARE MB program.[4300]

Mr. Cira-Reyes encouraged consideration of affordability success beyond mere disconnection rates, including consideration of customer satisfaction rates.[4301] Contrary to the Company's claims that the program was unsustainable, what Mr. Cira-Reyes contended was truly unsustainable is the energy insecurity of the LMI community.[4302] As a result, Mr. Cira-Reyes advocated that the Commission should mandate that Consumers adopt a PIPP for all customers at or below 200% of the FPL to simplify assistance offerings, and to ensure that interaction between multiple assistance programs did not worsen customer conditions.[4303]

Ms. Byrom responded that Consumers had previously had a PIPP pilot for both electric and natural gas services for households under 150% of the federal poverty level. The PIPP had comparable program metrics to other APPs, but had a higher maintenance cost, which "would be particularly pronounced if PIPP were extended to all" LI customers.[4304] The analysis also indicated that LI customers are successful and satisfied with existing CARE programs, and that, particularly in light of MEAP enhancements, continuing with existing MEAP programs was recommended. Ms. Byrom agreed with Mr. Cira-Reyes that abandoning the PIPP program was due to

---

[4299] 3 Tr 2317-2318.
[4300] 3 Tr 2318-2320.
[4301] 3 Tr 2318-2320.
[4302] 3 Tr 2320.
[4303] 3 Tr 2321.
[4304] 3 Tr 967.73-967.74.

higher costs, with PIPP estimated to cost $232 million per year in comparison to CARE MB, which is estimated to cost $156 million per year.[4305] Ms. Byrom concluded that the PIPP pilot in Case No. U-21021 was the most appropriate avenue for comments on the pilot and the resulting report.[4306]

Additionally, Elaina Braunschweig, a Departmental Analyst for the Rates and Tariff Section of the Regulated Energy Division of the MPSC, cited MCL 460.11(2) and the corresponding eligibility criteria found in MCL 460.10t(6)(b), in relation to UCC's recommended PIPP. She also noted that the Commission disallowed large-scale energy assistance reform in Case No. U-21585, finding the rate case an inappropriate forum for the policy debate.[4307] However, in the case specifically for the purpose, Staff filed its Energy Affordability Report in Case No. U-20757 in September 2025. According to Ms. Braunschweig, there are topics and recommendations in that report that could overlap or conflict with the UCC PIPP recommendation.[4308] Because "the Commission's last stated position directed energy assistance and affordability reform to disseminate from that report/the EAAC, Staff recommends the Commission take a consistent approach and align its decisions with the Staff report."[4309]

Review of the report indicates that, while DTE Energy reported good results with its pilot program, Consumers found that its MEAP-funded affordable payment plans performed similarly to the PIPP pilot, but with PIPP incurring higher costs.[4310] The report also found higher program completion rates through year one and year two of the PIPP

[4305] 3 Tr 967.74.
[4306] 3 Tr 967.75.
[4307] 3 Tr 4610-4611.
[4308] 6 Tr 4611-4612.
[4309] 6 Tr 4612.
[4310] September 10, 2025 Staff Energy Affordability Report in Case No. U-20757, pp. 54-55.

pilot in comparison to CARE and CARE MB. And the report highlighted differences between the DTE's and Consumers' programs that might have impacted the respective outcomes.[4311] The Commission has taken no action since the end of the comment period following the filing of the report.

Consumers' brief outlines the history of the PIPP pilot, and that the PIPP pilot's results are being considered in the other case.[4312] Consumers takes the position that it should not be required to implement a PIPP in this case while "the Commission is taking a more global approach to examining the PIPP, as well as other affordable payment plans," in U-21021.[4313] Consumers' reply voices support for Staff's recommendation to continue to explore energy assistance program modifications in Case No. U-20757.[4314]

UCC's brief substantially duplicates Mr. Cira-Reyes' testimony regarding the benefits of the PIPP pilot for customers, stressing that the PIPP program outperformed the Company's current assistance programs. Enrolled customers paid less out of pocket than those in CARE MB, and the program reduced energy burdens.[4315] The PIPP increased on-time payments and had higher completion rates in comparison to CARE and CARE MB. Based on customer reporting, they had a better experience with PIPP than with CARE.[4316] UCC also notes Staff's pilot analysis results supports a modification of affordable payment plans to include some elements of PIPP. From this, UCC asserts that PIPP had clear benefits. And it is not clear, from review of the PIPP report, that it was more expensive than CARE MB to administer. Any added administration costs are,

---

[4311] *Id*., 99-112.
[4312] Consumers brief, 444-445.
[4313] Consumers brief, 445.
[4314] Consumers reply, 29.
[4315] UCC brief, 32-33.
[4316] UCC brief, 34-35.

to UCC, worth the benefits to customers.[4317] UCC also contends that the instant rate case is proper to consider the PIPP based on the plain language of the settlement agreement in Case No. U-20650.[4318]

UCC's reply brief rejects Staff's recommendation that energy assistance programs be considered through Case No U-20757. Energy affordability should be considered in this case, and this is supported by the wording of the settlement agreement in Case No. U-20650, so UCC contends.[4319] And, in opposition to Ms. Braunschweig's testimony that the result in this case might "overlap, conflict, or agree" with Staff's report in Case No. U-20757, this should not preclude consideration of affordability and assistance programs in this case. A good solution now does not need to wait for a better solution later, particularly where the LIA and SPP, both assistance programs, are being considered in this case.[4320]

The Commission previously opted not to make any PIPP recommendations until the PIPP pilot program completed.[4321] The pilot has completed, but consideration of the PIPP pilot and other payment plans is ongoing in Case No. U-20757. Review of Staff's report in that case indicates that Commission action is likely to have a direct bearing on the question of PIPP adoption. In light of Staff's recommendation, this PFD finds it prudent to recommend no action be taken on UCC's PIPP recommendation until the Commission has taken action in relation to Staff's report in Case No. U-20757.

[4317] UCC brief, 35-39.
[4318] UCC brief, 39-41.
[4319] UCC reply, 16-17.
[4320] UCC reply, 18-19.
[4321] March 21, 2025 order in Case No. U-21585, pp. 387-388.

4. Low-Income Assistance Credits

The Company is proposing to increase the LIA credit from $30 to $42 per meter for 2026, with an annual scaled increase through 2029.[4322] Ms. Byrom testified that the Company is also proposing that the number of customers receiving the LIA credit increase to 6,200, with increases of 1,000 per year through 2029, which, in addition to complying with the 2024 Public Acts 168, 169, 170, and 198 improvements and modernizations of MEAP, is particularly needed as inflation and economic factors have challenged household sustainability.[4323] The funding increases by customer count are set forth in a table in Ms. Byrom's testimony.[4324]

Ms. Byrom indicated that customers currently eligible for LIA credits include customers whose total household income has not exceeded 150% of the federal poverty level within the last 12 months; who have received MEAP assistance; who have received a home heating credit energy draft; are in the state emergency relief program; who receive Medicaid; and/or who have received Supplementary Nutrition Assistance Program ("SNAP") benefits and whose total household income has not exceeded 150% of the federal poverty level within the prior year.[4325] If none of the requirements are met then the customer will need to complete and return a Company-provided low-income verification form.[4326]

Ms. Byrom explained that LIA credits are currently applied to 4,200 energy accounts of customers who are enrolled in the Consumers Affordable Resource For

---

[4322] 3 Tr 967.26, 967.38.
[4323] 3 Tr 967.38-967.39.
[4324] 3 Tr 967.39.
[4325] 3 Tr 967.39.
[4326] 3 Tr 967.39.

Energy (CARE) program, and the Company is proposing to make 5,200 credits available during the test year at a total cost of $2,788,623.[4327] This explanation is reiterated in Consumers' brief.[4328] Mr. Cira-Reyes generally supported the increase to the LIA credit and the expanded cap for the LIA credit.[4329] This support is reiterated in UCC's brief.[4330]

Apparently unopposed, this PFD recommends approval of the expanded LIA credit and cap, and the tariff change to facilitate the increases.

H. Pension/OPEB Volatility Mechanism

Ms. Grob testified that the Company requested to continue implementation of the Defined Benefit (DB) Pension/Other Post-Employment Benefit (OPEB) Volatility Mechanism (VM), which was previously authorized by the Commission in Case Nos. U-21585 and U-21389.[4331] She stated that the proposed mechanism, which mirrors the mechanism that has existed since 2023, would protect customers from volatility in future expenses by allowing the Company to defer annually the difference between the DB Pension/OPEB expense included in rates versus the actual annual expense recorded by the Company.[4332] She stated that in 2024, the Company recorded a DB Pension VM regulatory liability of $10,729,000 and projected amortization of ($1,912,000) for the test

[4327] 3 Tr 967.40.
[4328] Consumers brief, 446.
[4329] 3 Tr 2321.
[4330] UCC brief, 41. UCC reply, 2, 7.
[4331] 3 Tr 1136.
[4332] 3 Tr 1137.

year.[4333] She stated that the Company recorded an OPEB VM regulatory liability of $3,579,000 for 2024 and projected amortization of $1,813,000 for the test year.[4334]

This PFD recommends continuing accounting approval for the Pension and OPEB VM, as no party has raised any objection to doing so.

I. Disconnection Regression Analysis

In its order in Case No. U-21585, the Commission directed the Company to include a regression analysis of residential shutoffs as part of Consumers' ongoing analysis of equity issues. According to Ms. Byrom, as shown in Exhibit A-135, and discussed by Mr. Kelly, when all other variables were held constant, there was a statistically significant increase in shutoffs in communities with higher minority populations, a finding which was of concern to the Company.[4335]

Ms. Byrom explained that although Consumers does purchase aggregate customer data that includes race, that information is not available at the customer account level, and therefore race could not be a factor in the Company's disconnection strategy.[4336] Ms. Byrom testified that the Company takes seriously its commitment to providing equitable treatment to all customers and is concerned by any finding that indicates that customers in minority groups might face shutoffs at an inequitable rate. However, the Commission's directive to conduct this analysis was issued approximately two months prior to the filing date of the instant case, and the analysis itself was only completed approximately three weeks prior.[4337] Ms. Byrom testified that the Company

[4333] 3 Tr 1137-1138; Exhibit A-97, p. 1, lines 7, 9.
[4334] 3 Tr 1139; Exhibit A-97, p. 1, lines 8, 10.
[4335] 3 Tr 967.48.
[4336] Id.
[4337] 3 Tr 967.49.

was still analyzing the results to determine the next steps but planned to do so expeditiously by implementing an internal problem-solving process to identify causes, impact, and effective countermeasures to address the concerns raised by analysis, and the Company would provide relevant updates as the process was completed.[4338]

Mr. Cira-Reyes testified that the regression analysis revealed racial disparities in shutoff data for which the Company has provided neither an explanation nor concrete mitigation plans. He testified that the Company's 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." Mr. Cira-Reyes asserted that this indicated a racial bias in the Company's shutoff practices. While customers' racial identity was not expressly available to Consumers' employees engaged in the disconnection process, Mr. Cira-Reyes noted that Consumers confirmed in discovery that those employees have access to customers' names and addresses, which could nonetheless serve as race-identifying data points. Moreover, despite providing reports regarding customer segmentation by payment frequency and disconnection, the Company has failed to provide any meaningful information about why this bias exists. Finally, he noted that the problem-solving process, which was initially set to conclude on September 24, 2025, has been pushed to December 31, 2025, raising questions about whether resolving existing racial disparities was currently among the Company's top priorities.[4339] Based on his conclusions, Mr. Cira-Reyes recommended the Commission require the Company to

[4338] Id.
[4339] 3 Tr 2328-29.

cease all shutoffs until it can determine why black, indigenous, and people of color (BIPOC) customers are experiencing increased shutoffs, and further, direct Consumers to present a plan to stop that bias from continuing. He also asserted the Company should be required to create a fund to compensate customers shutoff by Consumers for improper reasons.[4340]

In rebuttal, Ms. Byrom testified that while there may be a racial component to the Company's shutoff rates, there was no racial bias, and certainly no purposeful bias. There were numerous factors that go into a Company-supported shut off, and neither race nor socio-economic statistics are included.[4341] Ms. Byrom stated that to conclude that employees associate name, address, or race with disconnection was groundless speculation.

Furthermore, when processing remote disconnections, which comprise the bulk of the residential disconnections processed annually, Ms. Byrum explained that Company employees could only see the internal customer account number eligible for disconnection and not the customer's name or address, further reducing any bias that Mr. Cira-Reyes suggested exists within the Company's process. Ms. Byrom stated that if either element were found to be true after assessment, appropriate corrective action would be taken.[4342]

According to Ms. Byrom, the Company committed to creating a cross-functional team to evaluate data relevant to the regression analysis, customer data related to payment behaviors, reviewing customer processes, etc. The cross-functional team

---

[4340] 3 Tr 2329-30.
[4341] 3 Tr 967.76.
[4342] 3 Tr 967.76-967.77.

includes members from credit and collections, data analytics, community affairs, and Diversity, Equity, and Inclusion.[4343] While the Company originally planned to complete its assessment in September 2025, Ms. Byrom noted that the timeline has been expanded to December 31, 2025 to allow for additional input and analysis.[4344] She stated that the Company has committed to addressing the issue noted in the regression analysis, which was a complex finding that required not only additional assessment but also planning and coordination for any identified solutions.[4345]

CEO witness Tan testified that, in Case Nos. U-21389 and U-021585, he recommended the use of regression analysis to analyze reliability metrics as a means of understanding how different communities experience outages. He explained that regression analysis allows analysis between dependent variables, like reliability metrics, and independent variables, such as grid characteristics and customer demographic information.[4346] In those cases, he used census tract demographics compared to Consumers' SAIFI, SAIDI, CAIDI, and grid archetype information; the inclusion of grid characteristics would allow Consumers to control for certain variables and test if they correlate to improving or worsening reliability.[4347] He also advocated in U-21585 that residential disconnections should be analyzed using regression analysis, indicating that his use of area median income and race in his analysis in that case indicated that

[4343] 3 Tr 967.77.
[4344] Id.
[4345] Id.
[4346] 4 Tr 3232.
[4347] 4 Tr 3232.

census tracts with higher numbers of BIPOC residents in their populations had more disconnections, even when income was held constant.[4348]

Mr. Tan testified that the Commission recognized the value of this regression analysis, ordering Consumers to run this analysis in its subsequent rate cases. Consumers complied, and it engaged an outside firm, Exponent, to undertake the analyses which were presented in this case by Mr. Kelly.[4349]

Mr. Tan discussed the finding that BIPOC communities experience higher disconnection rates, noting Ms. Byrom's representation that the Company takes its commitment to providing equitable treatment for all customers seriously, and that the finding of possible shutoff rate inequity was concerning.[4350] Although Ms. Byrom explained that the regression analysis was completed too late to be addressed in this rate case, Mr. Tan noted that Ms. Byron provided a preliminary analysis to UCC, including disconnection rates, dunning history, and available LMI data. He additionally requested that the Company, in rebuttal testimony, provide updates on the Company's internal discussions in relation to disconnection regression analysis, and provide any additional analyses completed since this case was filed.[4351] He further recommended that Consumers continue with regression analysis in relation to residential disconnections to track progress and address inequitable disconnection rates.[4352]

From this, Mr. Tan recommended that Consumers reevaluate its disconnection policies, suggesting a moratorium on residential disconnections until Consumers

---

[4348] 4 Tr 3232.
[4349] 4 Tr 3233-3234.
[4350] 4 Tr 3237.
[4351] 4 Tr 3237-3238.
[4352] 4 Tr 3238-3239.

proposes a solution to mitigate the disparity between BIPOC and non-BIPOC household residential disconnection rates.[4353] He asserted that "EJ circuit analysis is a good approach for understanding reliability," and he reiterated that the Company be directed to continue its regression analyses, particularly on residential disconnections, in addition to his other recommendations.[4354]

In rebuttal to Mr. Tan, Ms. Byrom reiterated that the Company is currently working to understand payment behaviors of customers and would have an update to share at the end of 2025. She further noted that since the initial regression results were made available, the Company had conducted "robust cross-functional problem solving to identify potential point of cause" and has designed a pilot to test countermeasures. The pilot was scheduled and the Company plans to share results at the end of 2025. Ms. Byrom stated that the Company would be open to having further conversation on revisiting the regression analysis within an aligned timeframe that allowed adequate time for the Company's pilot actions to conclude and inform next steps.[4355]

In response to Mr. Tan's and Mr. Cira-Reyes' recommendation for a moratorium on disconnections, Ms. Byrom explained that requiring the Company to stop disconnections would have a negative effect on all customers, with associated cost and cost recovery compromised. Additionally, she raised a concern that a disconnection moratorium would not stop customers from accruing charges and could put customers in a position where their energy bills become unaffordable because of past due balances. Finally, she noted that to receive SER funding customers must be in

[4353] 4 Tr 3238.
[4354] 4 Tr 3238-3240.
[4355] 3 Tr 967.78.

possession of a shut-off notice, meaning that customers would be unable to receive assistance if a moratorium were implemented.[4356]

In its brief, Consumers addresses the regression analysis finding, discussed above.[4357] In response to UCC's claims of racial bias, the Company reiterates that the allegation is speculative and unfair, emphasizing that employees can only see the internal customer account number eligible for disconnection and not the customer's name or address.[4358]

In response to the calls for a moratorium on residential disconnections from the CEO and UCC, the Company reasserts that requiring it to stop disconnections entirely would not have the desired effect.[4359] The Company maintains that a moratorium would merely cause customers to accrue unaffordable past due balances and prevent them from receiving assistance to help make their bills more affordable.[4360]

In response to Mr. Tan's recommendation to continue to run a regression analysis of disconnections, the Company asserts that it is not necessary. Using the results of the regression analysis, the Company designed a pilot to test countermeasures, which should provide results at the end of the year, after which, the Company would be open to discussions on revisiting the regression analysis. The Company reasserts that it takes its commitment to providing equitable treatment to all

---

[4356] 3 Tr 967.79.
[4357] Company brief, p. 447.
[4358] Company brief, pp. 447-48.
[4359] Company brief, p. 448.
[4360] Id.

customers seriously and is concerned by any finding that indicates that customers in minority groups might face shutoffs at an inequitable rate.[4361]

In its brief, UCC argues that the Company did not provide an explanation for the racial disparities shown in their regression analysis, which should have prompted immediate action on the part of Consumers to develop a mitigation plan to address these unjustified impacts.[4362] UCC continues to assert that the Commission should order Consumers to halt shutoffs until it addresses the disparities.[4363] UCC reiterates Ms. Byrom's testimony, and it maintains that the Company's practices fail the reasonableness standard set forth in MCL 460.557 on two independent grounds. First, the practices produce demonstrable racial disparities in shutoff rates. Racial disparities are inherently unreasonable because they affect access to essential utility services. Second, the Company has not provided any evidence that these disparate outcomes are justified by legitimate, non-discriminatory factors. If a utility's practices produce differences in service, at the same price to the customer, due to arbitrary racial disparities, the utility will have violated the "just and reasonable" standard.[4364]

UCC argues that because the Company has not addressed the policies and practices leading to racial disparity in disconnections, the only solution to ensure that racially disparate shutoffs do not occur during a period of investigation and proposal for corrective action is for the Commission to institute a shutoff moratorium. Such a moratorium would ensure that no one is shut off while the Company identifies the root

---

[4361] Id.
[4362] UCC brief, p. 68.
[4363] Id.
[4364] UCC brief, p. 69.

cause of the problem and takes action to address it.[4365] In conclusion, UCC reasserts the Commission must address the racially disparate outcomes in Consumers' shutoffs because racially disparate service provision cannot be considered just and reasonable. Therefore, UCC recommends the Commission require the Company to cease all shutoffs until it can determine why BIPOC customers are experiencing increased shutoff rates and implement measures to prevent racially disparate impacts asserting that the statute's reasonableness requirement demands Commission intervention.[4366]

In their brief, the CEO revisit Mr. Tan's testimony and argue that Consumers can act now to ensure that the Company does not perpetuate further inequality.[4367] The CEO argue that the Company's concerns about the downsides to ceasing shutoffs pending a more complete review are outweighed by the potential that the Company, even inadvertently, is applying its disconnection policies in a disparate manner. Accordingly, until the Company thoroughly reviews its own application of its policies, the CEO argues it should cease disconnections.[4368]

In its reply brief, the UCC asserts that the Company has not explicitly committed to a specific time by which it will implement countermeasures or change the policies and practices that have led to racial disparities in shutoffs. As a result, the UCC again argues that the Company's actions fail the just and reasonable and comparable treatment standards by producing demonstrable racial disparities in shutoff rates. To ensure that racially disparate shutoffs do not occur during the period of investigation and proposal for corrective action, the Commission should order the Company to halt

[4365] UCC brief, p. 70.
[4366] UCC brief, p. 71.
[4367] CEO brief, p. 25.
[4368] Id.

shutoffs while it investigates the cause and develops a comprehensive remedial plan.[4369] While UCC does not want customers to be in a worse position due to a temporary shutoff moratorium, it contends that the Company does not explain why a temporary shutoff moratorium would render balances unaffordable, lead customers not to pay their bills, or prevent customers from receiving funding assistance.[4370] UCC then concludes that the Company and Commission should implement any temporary moratorium within their legal authority that does not impede the access of qualifying customers to assistance. Where there may be an impediment to accessing assistance, the Company should be required to assess and implement mitigation measures within its authority to do so (e.g., pausing arrears accrual).[4371]

In its reply brief, CEO relied on the parties' testimony and previous briefing and renewed its arguments and requests for relief.[4372]

This PFD agrees with Consumers that the statistically significant result showing that minority households are more likely to experience disconnection is quite concerning. While the Company's testimony and exhibits show that when processing remote disconnections, Company employees can only see the internal customer account number eligible for disconnection, and not the customer's name, address, or race, something else is clearly occurring that appears to result in racial bias in the disconnection process.

That said, this PFD is not persuaded by the calls for a moratorium on residential disconnections from CEO and UCC. Customers are disconnected for non-payment, and

---

[4369] UCC reply brief, p. 24.
[4370] UCC reply brief, p. 25.
[4371] UCC reply brief, p. 26.
[4372] CEO reply brief, pp. 4-5.

this PFD agrees that a disconnection moratorium could result in large arrearage balances, putting low-income customers who are already struggling in an even worse position. This PFD also notes the Company's willingness to revisit the regression analysis and the CEO recommendation that the Company continue to run Exponent's regression analysis. Therefore, this PFD recommends the Commission direct the Company to revisit the regression analysis, once its pilot is complete, to evaluate how the pilot and countermeasures impacted disparity in disconnections.

J. State Reliability Mechanism

Ms. Davis presented Consumers' calculation of the State Reliability Mechanism (SRM) capacity charge at $116.17/MW-Day, while Company witness Jerore provided the inputs, cost offsets, and demand for the charge.[4373] According to Ms. Jerore, the capacity charge, "'is a retail rate, designed to recover the incumbent utility's cost of providing capacity service, to whatever type of customer load—bundled or choice' to ensure long-term resource adequacy to customers in the state."[4374] She testified that the Commission has recently approved SRM capacity charges for Consumers ranging from $65.13/MW-day in Case No. U-21585 to $374.95/MW-day in Case No. U-20697.[4375] She testified further that the Commission has consistently ruled that any changes to the calculation of the SRM capacity charge would require the re-opening of Case No. U-18239, where the calculation was originally approved.[4376] Accordingly, she asserted, Consumers is not proposing any changes to the calculation in this case, but may in the future request the re-opening of Case No U-18239 to propose changing the

[4373] 4 Tr 2662-2663; Ex. A-87.
[4374] 3 Tr 1782, quoting Case No. U-18239, Order, November 21, 2017, p. 73.
[4375] 3 Tr 1785.
[4376] 3 Tr 1785-1786.

calculation to prevent recovery of Consumers' full capacity costs, which is harmful to full-service customers, and to address MISO's new Seasonal Construct.[4377] Ms. Jerore presented the SRM reconciliation calculation or true-up as provided by Section 6w(4) of Public Act 341 of 2016. She explained that as directed by the Commission in Case No. U-21585, the Company is presenting the SRM reconciliation amount, even though the Company has never implemented the SRM capacity charge.[4378]

Staff witness Pung remarked that Consumers' SRM capacity revenue requirement calculation complies with the Commission's Order in Case No. U-21585, as it includes the true-up method. He testified, however, that Staff calculated the capacity charge at $111.99/MW-day, using the Company's calculation method but based on Staff's case.[4379]

Mr. Pung described the SRM statute and Consumers' and DTE's interpretations and approaches to the true-up provision in their most recent respective rate cases.[4380] According to Mr. Pung, the formulaic true-up method has significant flaws and has the potential to "throw the capacity and non-capacity revenue requirements far off the cost-to-serve."[4381] He provided as an example that in DTE's most recent rate case, U-21860, $1.12 billion of power supply revenue requirement is being shifted from non-capacity to capacity due solely to the formulaic true-up method based on the "large discrepancy" between DTE's forecasted amounts and 2024 actual amounts, primarily for energy

[4377] 3 Tr 1786.
[4378] Id.
[4379] 6 Tr 4575.
[4380] 6 Tr 4575-4577.
[4381] 6 Tr 4577.

market sales.[4382] He stated that in this case, the formulaic true-up is actually reducing the capacity revenue requirement by $461 million and artificially lowering the capacity charge, which he asserted demonstrates "the large swings in the capacity revenue requirement due to the formulaic SRM true-up method."[4383] He maintained that the capacity charge in this case without the true-up is $240.08/MW-day.[4384] He testified that in Staff's opinion, "the current formulaic true-up method is not producing a reasonable result that adheres to cost-of-service principles."[4385] He recommended that the Commission determine that a true-up is only necessary if a customer is actually subject to the capacity charge and there is actual revenue to reconcile. He asserted that this is how Consumers previously interpreted and applied the SRM true-up provision and this is how the true-up provision should be provided for going forward.[4386]

Similarly, Mr. Zakem from Energy Michigan recommended suspending the true-up provision in this case. He provided extensive testimony, including a description of the statutory directives related to the calculation of the charge and the true up, which is provided below:

> The Commission shall provide for a true-up mechanism that results in a utility charge or credit for the difference between the projected net revenues described in subsection (3) and the actual net revenues reflected in the capacity charge. The true-up shall be reflected in the capacity charge in the subsequent year. The methodology used to set the capacity charge shall be the same methodology used in the true-up for the applicable planning year.[4387]

[4382] Id.
[4383] 6 Tr 4578.
[4384] Id.
[4385] Id.
[4386] 6 Tr 4578-4579.
[4387] 6 Tr 4087; MCL 460.6w(4).

He explained that in practice, the true-up should be the difference between what the customer initially paid based on the SRM charge with forecasted sales and fuel versus the SRM charge recalculated with actual sales and fuel.[4388] He also described the history of SRM capacity charges since the enactment of the SRM statute in 2016 and noted that "there have been only four true-ups—all for DTE Electric."[4389]

He explained that an analysis of DTE's true-ups reveals a timing flaw in the SRM statute. He testified that none of the four DTE cases that included true-ups dealt with the immediately preceding case that set an SRM charge: one was trued up in two later cases and none were done in succeeding SRM cases, or in subsequent years, as the SRM statute requires.[4390] He posited that the drafters of the statute did not account for the significant time cases take, where an SRM charge is set at the date of the final order in a case, and the next setting is a year or more away, at the time of a final order in the next case, not at the time of the filing of the next case.[4391] He continued that under the present true-up method the customer and the utility can only be trued up if the customer that pays an SRM charge in one year also pays an SRM charge determined in a later year, but if the customer pays the SRM charge also in a later year, then that later charge would not get trued up until a still later case, such that SRM charges and true-ups end up "infinitely pancaked."[4392]

[4388] 6 Tr 4089; Ex. EM-2.
[4389] 6 Tr 4094-4095, Table 1; Ex. EM-3.
[4390] 6 Tr 4096, quoting MCL 460.6w(4)("The true-up shall be reflected in the capacity charge *in the subsequent year*")(emphasis added).
[4391] 6 Tr 4096-4097.
[4392] 6 Tr 4098.

He contended that this flaw results in the present true-up method being contrary to cost-of-service principles and unfair to both the utility and the customer.[4393] He provided an example, which he asserted shows that under the present true-up method no matter what time period or combination of time periods a customer may pay the SRM capacity charge, the total charge the customer pays and the utility collects is always in error.[4394] He maintained that it charges customers and compensates the utility an amount different from the defined amount in every situation and also conflicts with the cost of service statute, MCL 460.11(1).[4395]

Mr. Zakem noted that in his opinion, the SRM statute provides the Commission with a degree of flexibility in exactly how it can implement a true-up process that is guided by cost of service principles.[4396] He testified that the Commission has also recognized this flexibility, noting that in Indiana Michigan's (I&M's) initial SRM case the Commission declared that "nothing in Act 341 requires that I&M's capacity rate be set using the mechanism set forth in the statute" and that the statute provided "guidance," which along with the evidence about an "equitable and accurate rate for capacity" made it appropriate to revisit the SRM methodology.[4397]

Mr. Zakem presented what he called a "straightforward remedy" to the current SRM method's flaws: suspend the current formulaic true-up method in this proceeding and apply a customer-specific true-up to any customer that is assessed the SRM in the

---

[4393] Id.
[4394] 6 Tr 4099-4103.
[4395] 6 Tr 4103.
[4396] 6 Tr 4105-4106.
[4397] 6 Tr 4107, quoting Case No. U-18370, Order, April 12, 2018, p. 71.

future.[4398] He asserted that suspending the use of the current method is essential, because using the current method continues and prioritizes a known error over the equitable and accurate implementation of a statute.[4399] He maintained that it is not necessary to reopen Consumers' past SRM case to suspend the provision.[4400] He opined that it would be at least six years before the true-up would have to be addressed and if at some time in the future a customer does pay the SRM charge and require a reconciliation, that it can be done on an ad hoc basis for that customer without revising present or future SRM charges.[4401]

Mr. Zakem described a simple true-up method where the difference between what a customer initially paid based on projections is compared to what they should pay based on actuals, and they are billed for, or refunded, the difference.[4402] He contended that this way, both the customer and the utility would be treated fairly, and no "gaming" of high forecasts or low forecasts would be possible.[4403] He added that it eliminates another inherent error of the present formulaic method, which is that the customer does not necessarily have the same MW capacity obligation in two different periods. And finally, he maintained, it fulfills the SRM statute in a manner parallel to the determination of the initial SRM charge.[4404] He provided an example of how his simplified true-up method would work.[4405]

[4398] 6 Tr 4108-4109.
[4399] 6 Tr 4108.
[4400] Id.
[4401] 6 Tr 4108-4109.
[4402] 6 Tr 4109.
[4403] Id.
[4404] Id.
[4405] 6 Tr 4110-4111,

According to Mr. Zakem, his proposed method provides seven advantages: 1) both the customer and the utility are treated equitably and accurately; 2) the customer does not have to pay an SRM charge in multiple periods just to be trued up for one period; 3) the rates for full-service customers are no longer affected by errors in projecting energy market sales net of fuel; 4) there is no need for pancaking or reversals or re-reversals of previous true ups; 5) the customer's MW capacity obligation, which can be different in two different periods, and upon which the SRM charge to be assessed is based, becomes irrelevant; 6) the recalculation of the SRM charge using the actual energy market sales net of fuel is readily visible, and easily comparable "before" and "after;" and 7) it eliminates any opportunity for "gaming" the SRM charge either by the utility or by AESs, via skewing projections of offsets up or down.[4406]

Mr. Zakem posited that the Commission and interested parties have at least six years to come to agreement, if the current formulaic method is suspended. He opined that “the arithmetic is so simple that I can't see reopening six contested SRM cases to figure it out.”[4407] He described how the suspension of the true up method in this case would change Consumers’ proposed SRM capacity charge from $116.17/MW-day to $244.36/MW-day.[4408]

Consumers did not provide rebuttal testimony on the SRM capacity charge or true-up calculation. However, Mr. Zakem provided rebuttal testimony showing the calculation of the SRM capacity charge with a suspended true-up provision, based on

[4406] 6 Tr 4111-4112.
[4407] 6 Tr 4112.
[4408] 6 Tr 4113; Ex. EM-4.

Staff's proposed case. He asserted that his calculation matches Staff's calculation of $240.08/MW-day, except for a minor rounding difference.[4409]

Consumers' brief repeats Ms. Jerore's and Ms. Davis's testimony but does not comment on Staff's and Energy Michigan's testimony about the flaws in the true-up formulaic method.

Staff's brief largely recaps Mr. Pung's testimony and agrees with Energy Michigan witness Zakem that the formulaic true-up method "should be discontinued and removed in this case" and Consumers should "perform a true-up only if a customer is actually subject to the capacity charge and there is actual revenue to reconcile."[4410] Quoting MCL 460.11, Staff states that "[c]ost-of-service based ratemaking is a cornerstone of electricity regulation," and the Commission has repeatedly acknowledged that ratemaking must reflect cost-of-service principles and be consistent with the requirements of MCL 460.11.[4411] Staff also posits that MCL 460.6w(4) gives clear authority to the Commission to provide for the true-up mechanism using multiple methods.[4412] Staff further agrees with Energy Michigan and recommends that any reconciliation should be done in a customer-specific manner to avoid capacity and non-capacity revenue requirements in subsequent years that do not reflect the cost-to-serve.[4413] Staff opines that, "apart from calculating an entirely separate rate design with actual energy market sales figures for the express purpose of an SRM reconciliation,"

[4409] 6 Tr 4118-Tr 4119; Ex. EM-5.
[4410] Staff initial brief, p. 152-153.
[4411] Id., p. 152, citing Case No. U-21389, Order, March 1, 2024, p. 248; Case No. U-20162, Order, May 2, 2019, p. 129.
[4412] Staff initial brief, p. 152.
[4413] Id., p. 153.

Energy Michigan's proposal to implement a customer-specific SRM true-up is a reasonable method."[4414]

Energy Michigan's brief largely repeats and elaborates on Mr. Zakem's testimony. Energy Michigan contends that it is impossible for the Commission to implement the SRM statute's provision that the true up is reflected in the subsequent year, thus the Commission "must exercise some discretion and flexibility in implementing a method for trueing up the SRM Charge."[4415] According to Energy Michigan, the Commission should consider the following three elements: 1) the cost-of-service statute, which dictates that the true up method is equitable and accurate; 2) the explicit language in MCL 460.6w(4) such as "shall provide for a true up mechanism" and the true-up, and not the mechanism, "shall be reflected in the capacity charge in the subsequent year;" and 3) previous Commission decisions, such as Case No. 18370, I&M's original true up case.[4416] Energy Michigan contends that the parties agree and the evidence supports suspending the true-up method in this case and implementing a true up if and only if a customer pays an SRM charge.[4417] Furthermore, Energy Michigan argues that since the math is so simple, there is no need to reopen six SRM cases and the Commission can decide to implement a customer-specific SRM true-up process in this case and then establish one docket to receive proposals and comments for that single objective.[4418]

[4414] Id.
[4415] Energy Michigan initial brief, p. 6.
[4416] Id., p. 8-10.
[4417] Id., p. 12.
[4418] Id., p. 18.

Neither Consumers nor Staff addressed the SRM capacity charge or true-up mechanism in their reply briefs. Energy Michigan's reply notes Staff's agreement that the current SRM Charge true-up method does not follow cost-of service principles and should be changed.[4419] Energy Michigan also responds to Consumers' statement that it may propose a calculation method "that does not result in a charge that prevents recovery of the Company's full capacity costs and, as a result, unfairly harms full-service customers."[4420] Energy Michigan contends that nowhere does Consumers support or explain this statement or how the current SRM process prevents recovery of their capacity costs or unfairly harms full-service customers. However, Energy Michigan avers that full-service customers and AES Electric Choice customers should both be treated fairly under any SRM process and pay the cost of providing service, and "if equal treatment is not occurring, then changes should be made."[4421]

Energy Michigan also remarks that Consumers' definition of the SRM Capacity charge adds the qualifier that it is intended "to ensure long-term resource adequacy to all customers."[4422] According to Energy Michigan, whether or not the SRM capacity rate can recover the incumbent utility's cost of providing capacity service or ensure long-term resource adequacy, are still open questions.[4423] Energy Michigan also notes that at the time of Consumers' initial SRM Case, No. U-18239, many important concepts were not well understood, such as MISO terms of art and how the MISO resource adequacy process actually works, as well as an appreciation for the cost-of-service statute.

[4419] Energy Michigan reply brief, p. 1.
[4420] Id., p. 3.
[4421] Id.
[4422] Id., p. 3-4.
[4423] Id., p. 4.

Energy Michigan suggests that properly understanding these concepts "may lead to implementation of a new SRM charge solution that satisfies both the utility and the customer."[4424]

This PFD finds that Energy Michigan's proposal is detailed, necessary, well-supported, and agreed to by Staff, and although Consumers did not comment on it, the Company previously maintained in Case No. U-21585, that the true-up mechanism should only be implemented if a customer actually pays the SRM charge. This PFD agrees that the current formulaic method is contrary to cost-of-service principles, it is impossible for a true-up to be reflected in the SRM charge in the subsequent year, and the Commission has authority to use discretion to implement a true up that is equitable and accurate. Accordingly, this PFD recommends that the Commission suspend the current formulaic true-up method and implement a customer specific true-up, when and if, a customer actually pays the SRM capacity charge and there is actual revenue to reconcile. This PFD also agrees with Energy Michigan that it is not necessary to open six SRM cases and therefore recommends that the Commission establish a new docket to receive proposals and comments to implement a customer-specific true up mechanism.

K. Virtual Power Plants

Mr. McPhail testified that Consumers' Distributed Energy Resource (DER) Optimization Initiative seeks to develop standardized methodologies to safely integrate DER into the electric distribution system. He added that this includes research, planning, and development of hardware and software to evaluate DER management

[4424] Id.

capabilities across the spectrum of DER types through the implementation of a DER Management System (DERMS).[4425]

Mr. McPhail described the Initiative's current activities and plans. He asserted that Consumers will create a workgroup of interested parties to collect feedback on the Initiative, as it agreed to do in Case No. U-21585. Additionally, he testified that Consumers will continue to participate in the Electric Power Research Institute's (EPRI's) DER Integration program, as well as explore additional DERMS working group opportunities in other states. He added that Consumers intends to onboard a consultant to facilitate its workgroup and develop a formalized business case, including a comprehensive BCA and an analysis of Virtual Power Plants (VPPs), to inform investment requests in future cases.[4426]

Mr. Kelly testified that Consumers has conducted pilots and studied non-wires solutions (NWS) over the last ten years. He noted that Consumers recently completed two NWS pilots, which showed that successfully deploying NWS on the Company's system and generating benefits from those NWS would prove difficult.[4427] He testified that Consumers found that for even a relatively limited use case such as deferring an LVD substation capacity upgrade, significant lead time was needed to procure the non-wires resources and the benefits were either unclear or insufficient.[4428] He maintained that using NWS to deliver reliability benefits, as opposed to capacity benefits, requires more certainty about deployment schedule and actual reliability parameters and as far as Consumers is aware, no U.S. utility has developed an NWS that works as an off-the-

[4425] 3 Tr 1724.
[4426] Id.
[4427] 3 Tr 1419-1420.
[4428] 4 Tr 1420.

shelf solution to improve distribution reliability.[4429] He asserted that while Consumers believes its findings are valid, it is still working to develop a new pilot to explore approaches beyond those used previously and plans to file a proposal through Case No. U-20898 as soon as possible.[4430]

CEO witness Kenworthy described a VPP:

> 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.[4431]

He testified that in Case No. U-21585, the Commission made it clear that Consumers must support DERMS-related investments with a robust business case, which must include an analysis of VPPs.[4432] He asserted that the CEO looks forward to being a part of Consumers' workgroup and he recommended that it be "expeditiously" convened. Additionally, he requested that Consumers discuss its plan and timetable for the workgroup in rebuttal testimony.[4433] He opined that a pilot VPP program is unnecessary and Consumers "is ready to begin implementation of a VPP starting initially as an extension of and building upon its residential demand response programs and rolling out additional program elements providing additional layers of value as the tools needed become available."[4434]

[4429] Id.
[4430] Id.
[4431] 4 Tr 3206.
[4432] 4 Tr 3201-3202, quoting Case No. U-21585, Order, March 21, 2025, p. 117-118.
[4433] 4 Tr 3202.
[4434] 4 Tr 3202-3203.

Mr. Kenworthy acknowledged that MISO isn't planning to comply with FERC Order 2222, which requires that DER aggregators be able to participate in wholesale energy markets, until 2030. But he maintained that Consumers does not need to wait for 2030 to realize VPP benefits. He asserted that Consumers can run utility-sponsored, retail-tariff VPPs now to deliver peak reduction, reliability, and targeted transmission and distribution (T&D) deferrals.[4435] Citing a 2025 update report from the Department of Energy (DOE) on VPPs, "Pathways to Commercial Liftoff: Virtual Power Plants," he stated that utility-led VPPs can be stood up in under six months with modest capital investment.[4436] He also noted that a VPP test event in California demonstrated that VPPs perform when needed most, that is during system peak.[4437]

Mr. Kenworthy recommended using Consumers' Residential Demand Response (DR) programs as a basis for a VPP program. He asserted that the thermostat DR program already uses an aggregator platform (EnergyHub), established enrollment channels, and event operations, which are all critical building blocks for VPP. He added that as DERMS matures, Consumers could layer in additional DERs and enable location-aware dispatch in coordination with ADMS.[4438]

Mr. Kenworthy outlined several design elements a residential VPP program should include: 1) a multi-technology approach that stacks customer devices; 2) simplified enrollment, such as by one-click/QR; 3) pay-for-performance contracts with third-party aggregators; 4) procuring VPP capacity that targets distribution needs; 5) carve-ins for low- and moderate-income customers; 6) and including VPPs in IRP/DSP

[4435] 4 Tr 3210.
[4436] 4 Tr 3210-3211; Ex. CEO-3.
[4437] 4 Tr 3210; Ex. CEO-4.
[4438] 4 Tr 3209.

portfolios.[4439] According to Mr. Kenworthy, Consumers should build on its commitment to model distributed generation as a resource and model VPPs.[4440]

Mr. Kenworthy recommended that the Commission require Consumers to file a VPP proposal within six months that includes program tariffs, aggregator contracts, enrollment channels, capacity targets, and measurement and verification. He also recommended that the Commission condition DERMS/Grid Edge capex on the VPP filing approval and performance metrics, adopt a benefit-cost framework that credits resource adequacy, ancillary services, and T&D deferrals, with pay-for-performance settlement, and de-couple VPP deployment from FERC Order 2222 implementation so that retail VPPs can move forward now.[4441]

Mr. Kenworthy testified that findings from other programs should be used to inform the development of VPPs. For example, he maintained that the Whole Home Optimization Pilot should be framed as Phase I of a VPP.[4442] Noting that the Commission required utilities to evaluate NWS and consider DERs as part of their distribution system planning, he recommended that these investigations be framed as part of the VPP development workstream.[4443] Lastly, he opined that while additional investigation on NWS is important, "the time for pilots is over" and Consumers should develop a formal NWS program.[4444]

GLREA witness Boehnke echoed Mr. Kenworthy on the benefits of VPPs. Like, Mr. Kenworthy, he cited the 2025 DOE report "Pathways to Commercial Liftoff: Virtual

---

[4439] 4 Tr 3211-3212; Ex. CEO-3.
[4440] 4 Tr 3212, citing Case No. U-21090, Order, June 23, 2022, p. 46-47.
[4441] 4 Tr 3214.
[4442] 4 Tr 3216.
[4443] 4 Tr 3218-3219, citing Case No. U-20147, Order, July 10, 2025, p. 29-30, 44-45.
[4444] 4 Tr 3218.

Power Plants," as well as several other reports to support his positions. He described the services a VPP can provide, such as voltage support and transmission congestion relief, and noted that while some of these services are valued in current markets, others, such as distribution deferrals are not.[4445]

He testified that VPPs also support flexible load growth, which is the addition of load that can be curtailed during peak stress periods. He explained that approximately 18.5 GW of new load could be added to the grid in the MISO region solely based on if the load were able to be flexible at peak times.[4446] He asserted that VPPs can complement such load growth based on the capability to aggregate flexibility in the forms of load reductions, shifting, and peak shaving.[4447] He recommended an assessment of the available headroom within Consumers' service territory that would be enabled by the curtailment of new load and he suggested that such a study could be required through the IRP process.[4448]

Mr. Boehnke asserted that VPPs are significantly less costly and faster to implement than traditional resources. He testified that a 400 MW resource from a VPP is roughly 60% of the cost of a battery system of the same size, and roughly 40% of the cost of traditional generation, and on a cost per kW basis, a basic VPP costs $43 per kW-year, compared to $69 for a Utility-Scale Battery, and $99 for a Gas Peaker plant.[4449] He further asserted that VPPs can be deployed in very short time frames,

[4445] 4 Tr 3220-3283.
[4446] 4 Tr 3288.
[4447] Id.
[4448] 4 Tr 3288-3289.
[4449] 4 Tr 3289-3290, Fig. 7.

delivering services in as little as 6 to 12 months, compared to the median deployment time of 42 months for a Gas Peaker plant.[4450]

Mr. Boehnke asserted that Consumers fails to recognize the role VPPs, and other DERs, can play in achieving reliability and resiliency. He maintained that Consumers has not adequately studied VPPs or quantified the impacts of EE and DR resources in its infrastructure planning process. He added that Consumers indicates that it has no research and development budget for VPPs, has no current pilot VPP pilot programs, and has not conducted any cost-benefit analysis of VPPs.[4451]

Mr. Boehnke described various VPP models already delivering grid impacts, which are deployed in other states, such as National Grid Connected Solutions in Massachusetts and New York; Cool Rewards in Arizona, Green Mountain Power Energy Storage System Leasing Program in Vermont; Wattsmart in Utah; ConEd Brooklyn Queens Demand Management Program in New York; and the California Market Access Program.[4452] He asserted that each of these VPPs created a market for grid resources by defining resources using standard weights and measures, valuing each resource, and providing a mechanism to trade on the resource.[4453]

Mr. Boehnke asserted that it is important to understand the potential that exists for VPPs based on Consumers' current funding and infrastructure. He opined that the Commission could implement a framework where EWR becomes a launching point for VPPs and since EWR programs are already rate-based, it is entirely possible that the

[4450] 4 Tr 3291.
[4451] 4 Tr 3293.
[4452] 4 Tr 3295-3300.
[4453] 4 Tr 3300-3305.

first VPPs in Michigan could be launched without securing additional funding.[4454] He testified, however, that while existing EWR programs have been successful, their systems of implementation and evaluation are insufficient to deliver peak reductions or infrastructure support. Furthermore, he added, Consumers does not use quantified impacts from its EE, DR, or DER programs as a part of its infrastructure planning processes.[4455] He pointed out that while Consumers does not measure the impact of installed DERs, it simultaneously claims that DERs are not yet able to deliver grid reliability and resilience.[4456] He asserted that a meter-based analysis of all programs for the past 3 years would provide a baseline of data for EE, DR, and DERs installed at host sites informing an analysis and valuation that could create the business case for VPPs.[4457]

Mr. Boehnke suggested that the primary roles required to run a VPP, such as Buyer, Seller, Program Administrator, Market Manager, and Host, could all be assumed by the utility, but need not be.[4458] He asserted that the most important thing is to create a market where the resources aggregated in VPPs can be bought and sold.[4459] He stated that there "hundreds of thousands of non-aggregated assets in the State in the form of electric vehicles to home batteries, thermostats to heat-pump-water heaters, distributed generation, and more that are currently available for deployment."[4460] He recommended a suite of actions that should immediately be taken to begin laying the

---

[4454] 4 Tr 3305-3306.
[4455] 4 Tr 3307.
[4456] 4 Tr 3308.
[4457] 4 Tr 3311-3312.
[4458] 4 Tr 3315-3316.
[4459] 4 Tr 3316.
[4460] 4 Tr 3327.

foundation for VPP development and aggregation: 1) establish a transparent, replicable system of measurement and verification; 2) complete a meter-based assessment Backcast and Targeting Exercise of the Company's EWR programs for the past 3 years; 3) require that VPPs be included in the IRP process; 4) require the assessment of EWR programs as a foundation for assessing the cost of delivery for a VPP.[4461] After these steps, in the following year, he recommended the completion of a headroom assessment for Consumers' (and DTE's) territories and a BCA, and, lifting of the partial ban on retail aggregation.[4462]

MEIU witness Albers expressed concerns that the deployment of VPPs, DERs, and EV charging stations could be delayed because of the long lead times associated with obtaining transformers and other critical equipment. He stated that based on his testimony in Case No. U-21585, the Commission found it appropriate that in this rate case Consumers identify equipment generally needed for DER and EV interconnections that have a long lead time and propose a propose a plan to maintain an adequate inventory of that equipment to support future development.[4463] Mr. Albers opined that Consumers satisfied the first directive as Mr. Kelly identified the equipment generally needed for DER and EV interconnection, but it was unclear whether Consumers satisfied the second directive."[4464] He acknowledged that Consumers provided additional information in discovery, including its 2022-2024 quarterly inventory of each category of equipment, the number of items used to interconnect DERs and EV charging infrastructure projects not initiated by the company from 2022-204, and the

[4461] 4 Tr 3327-29.
[4462] 4 Tr 3329-30.
[4463] March 21, 2025 Order in Case No. U-21585, p. 42.
[4464] 6 Tr 4229.

acquisition lead time associated with each category of equipment the last time it was ordered.[4465] He maintained that while there are some discrepancies in acquisition lead times, it does appear that Consumers maintains a sufficient inventory of the listed equipment.[4466] He recommended that that the Commission require Consumers to make its inventory of equipment with long acquisition lead times available to third-party DER and EV projects on the same basis that such equipment is available for Consumers' own projects.[4467]

Mr. Kelly, Mr. McPhail, and Mr. Blumenstock provided rebuttal to Mr. Kenworthy, Mr. Boehnke, and Mr. Albers. Mr. Kelly disagreed with the suggestion that VPPs can be deployed immediately in Consumers' service territory and reach operational status within six months without the need for any kind of pilot.[4468] He discounted the suggestion that VPPs are mature, such that Consumers can "easily plug and play them onto its own system."[4469] He noted that Exhibit CEO-4, which was used by Mr. Kenworthy to support this contention, suggests otherwise, as it describes a "test" event in California from July 2025.[4470] He added that each state has its own regulatory construct, and Michigan's is different from California's, such that there is no assurance that even a mature and well-established VPP in California under the California Independent System Operator (CAISO) could be transplanted wholesale to Michigan and MISO.[4471] He added that this would require a pilot to determine if the VPP would

[4465] 6 Tr 4230.
[4466] 6 Tr 4231.
[4467] Id.
[4468] 3 Tr 1609.
[4469] Id.
[4470] Id.
[4471] Id.

work on Consumers' system, but he suggested that Consumers' workgroup could discuss it.[4472]

As for NWS, Mr. Kelly maintained that Consumers must do another pilot to demonstrate that it can deliver benefits in a safe manner. He added that it would be irresponsible to begin implementing a program that may not be effective.[4473] He also testified that while NWS could be an additional topic for Consumers' DERMS workgroup, the synergy between VPPs and NWS also provides further evidence that neither concept is ready for immediate program-level deployment.[4474] He maintained that much of Mr. Kenworthy's (and Mr. Boehnke's) discussion centers around "basic VPPs," but the DOE report so extensively cited, "makes these basic VPPs sound closer to pilots in all but name."[4475] And he maintained that delivering the grid-wide benefits contemplated by Mr. Kenworthy (and Mr. Boehnke) requires the development of sophisticated VPPs.[4476] He asserted that Consumers would not be in a position to deploy these kinds of VPPs or NWS unless and until it has made the appropriate foundational investments, particularly in a DERMS.[4477] 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, he asserted.[4478]

[4472] 3 Tr 1609-1610.
[4473] 3 Tr 1610.
[4474] 3 Tr 1611.
[4475] Id.
[4476] Id.
[4477] 3 Tr 160-1611.
[4478] 3 Tr 1611.

Mr. Kelly responded to Mr. Albers' recommendation that Consumers make its inventory of equipment with long acquisition lead times available to third-party DER and EV projects. He asserted that based on Consumers' interpretation that Mr. Albers was referring to third party-initiated projects, not those conducted by third parties, Consumers already does what Mr. Albers requests.[4479] He explained:

> 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.[4480]

In his rebuttal, Mr. McPhail agreed that the DERMS workgroup would be helpful in developing a BCA for VPPs, but he contended that a BCA is premature at this time, considering the ongoing efforts to standardize an evaluation method for DERs in Case No. U-20898.[4481] He noted that Consumers is not requesting recovery for DERMS in this rate case.[4482]

While he agreed conceptually with Mr. Kenworthy's and Mr. Boehnke's definitions of VPP, he stated that it is unclear if VPPs in their present state of development can deliver the full stack of benefits included in the definition.[4483] As for the statements that VPPs are mature and can provide utility-scale and utility-grade service,

---

[4479] 3 Tr 1623-1624.
[4480] 3 Tr 1623.
[4481] 3 Tr 1748.
[4482] Id.
[4483] Id.

he asserted that such claims are premature and require verification.[4484] He added that until VPPs are fully integrated into utility systems it remains unclear whether they can deliver the multitude of ascribed grid benefits outside of the reduction of peak demand.[4485] He added that a VPP that does not respond to dispatch signals could potentially put the grid at risk.[4486]

He testified further that while Mr. Kenworthy seems to acknowledge the limitations of VPPs absent integration into utility operational systems such as DERMS/ADMS, Mr. Boehnke's suggestion that utilities do not necessarily need to fill the primary roles to implement a VPP, such as the program operator role, indicates he may not.[4487] He contended that Consumers "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."[4488] He asserted that Consumers' 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 the VPP does not.[4489]

Mirroring Mr. Kelly's testimony, Mr. McPhail asserted that VPPs are not ready for immediate implementation outside of a pilot process and mandating VPP implementation raises concerns, particularly because of the lack of established technical standards.[4490] He stated that while the DOE report lists several

---

[4484] 3 Tr 1749.
[4485] Id.
[4486] Id.
[4487] 3 Tr 1750.
[4488] Id.
[4489] Id.
[4490] Id.

standardization efforts, very few are complete.[4491] However, he indicated that Consumers is interested in participating in EPRI's FlexIT initiative, which seeks to establish standards for the core utility-to-VPP/aggregator interactions.[4492] He contended that mandating widespread implementation of VPPs outside of an established pilot process would cause unnecessary risks to system integrity, operational efficiency, and customer reliability and it would be premature to impose any VPP requirements other than what the Commission has already ordered.[4493]

Mr. Blumenstock disagreed with Mr. Boehnke's suggestion that VPPs should be included in Consumers' IRP process and Mr. Kenworthy's recommendation that Consumers develop a modeling approach for VPPs.[4494] He maintained that the Commission's IRP Filing requirements are provided in Case No. U-18461 and the Commission also created Case No. U-21570 to consider updates to the Michigan Integrated Resource Planning Parameters and IRP filing requirements in response to legislative directives.[4495] He maintained that IRP modeling requirements should be addressed in these utility-wide cases and not in separate rate cases.[4496]

In rebuttal testimony, Mr. Boehnke took issue with Mr. Kenworthy's statement that a VPP organizes customer flexibility into dispatchable capacity. He stated that while many VPPs offer "dispatchable capacity" as Mr. Kenworthy mentions, dispatchability is not required to support grid reliability.[4497] He asserted that defining VPPs broadly allows

---

[4491] 3 Tr 1751.
[4492] 3 Tr 1751-1752.
[4493] 3 Tr 1752.
[4494] 3 Tr 1623-1624.
[4495] Id.
[4496] Id.
[4497] 4 Tr 3332-3333.

the full value of these resources to be captured, so they can be procured by VPP operators.[4498]

In his rebuttal testimony, Mr. Albers generally agreed with Mr. Kenworthy's and Mr. Boehnke's recommendations regarding developing a VPP program in conjunction with a DERMS.[4499] However, he proposed adding the following requirements on Consumers: 1) incorporate its existing DR programs into any VPP program it develops; 2) meaningfully engage interested parties, such as by holding and publicizing multiple virtual meetings to share preliminary tariff language and solicit input on VPP program design, including by written feedback; 3) identify best practices in its VPP development process.[4500] He also recommended that the Commission encourage Consumers to avail itself of available resources, such as the CHARGED Initiative, which directly assists utilities to develop new programs and tariffs without additional cost to the utility.[4501]

In its brief, Consumers argues that the Commission has no authority to require the Company to purchase or otherwise exercise the managerial discretion to use VPPs.[4502] Consumers asserts that it already has robust EWR and DR programs, which are being considered in other proceedings.[4503] Consumers emphasizes that it has not developed an additional VPP program that involves the dispatch of DERs, as it does not agree that the technology is mature enough and it does not have the technological capability needed to run such a program.[4504] Noting the lack of standardization for

---

[4498] 4 Tr 3337.
[4499] 6 Tr 4237.
[4500] 6 Tr 4238-4242.
[4501] 6 Tr 4221-4223.
[4502] Consumers initial brief, p. 451.
[4503] Id., citing Case Nos. U-21680, U-21671, and U-21829.
[4504] Id., p. 451-452.

VPPs, Consumers rejects all of the CEO's recommendations pertaining to the development of a VPP program.[4505] Consumers asserts that without standardization, "utilities must manage multiple tailored interfaces, data formats, and communication protocols and such complexity increases the risk of operational inconsistencies, cybersecurity vulnerabilities, and higher implementation and maintenance costs.[4506]

Consumers also rejects GLREA's recommendations to develop a measurement and verification system for EWR, Demand Response, and DER programs, again asserting that such requests are addressed in other proceedings.[4507] As for lifting the partial ban on aggregators of retail customers, Consumers contends that it requires industry-wide participation, such as in Case No. U-21099.[4508]

Noting that MEIU's additional recommendations for a VPP program were introduced in rebuttal, Consumers argues that while the recommendations may be suitable to consider in a DERMS workgroup, they are generally premature or unnecessary.[4509]

In its brief, the CEO rejoins Consumers' assertions that VPPs are not ready for implementation, asserting that the Company provides no evidence to support its assertions and is just trying to cast doubt on VPPs.[4510] The CEO points out that Consumers did not directly rebut its proposal to use residential DR programs as a launching pad for a VPP program.[4511] CEO also disputes Consumers' characterization

---

[4505] Id., p. 452.
[4506] Id., p. 452-453.
[4507] Id., p. 454, citing, e.g., Case No. U-21671 and U-21647.
[4508] Id., p. 454.
[4509] Id., p. 454-455.
[4510] CEO initial brief, p. 9.
[4511] Id., p. 9.

of NWS, as well as its benefits, and recommends that the Commission reject Consumers' framing of NWS, and order the Company to transition its NWS offering into a permanent program in its upcoming distribution system plan.[4512]

In its brief, GLREA argues that the Commission has the legal authority to advance the implementation of VPPs in Consumers' service territory "as an endemic part of the Commission's duties to set and maintain just and reasonable rates, affordable electric service, and to require reasonable and prudent utility policies and practices."[4513] GLREA provides numerous authorities to support its claim, including: the Commission's duty to set and maintain "just and reasonable" rates;[4514] regulate PSCR costs;[4515] investigate rate and service issues;[4516] and inspect the books and records of a utility.[4517] GLREA maintains that several other statutes and rules support the Commission's broad jurisdiction and powers.[4518] GLREA also notes the Commission's authority to conduct IRP, EWR, and REP cases, to regulate DG, and to investigate the utility's proposed revenue requirement in a rate case.[4519] GLREA argues that Michigan

---

[4512] Id., p. 12-14.
[4513] GLREA initial brief, p. 2.
[4514] Id., citing *Attorney General v PSC*, 189 Mich App 138, 146 (1991); *Northern Michigan Water Company v Public Service Commission*, 381 Mich 340, 351 (1968); Sections 4(a) and (b), 6(a), 10(g), 22 and 32 of the Railroad Act, 1909 PA 300, MCL 462.4(a) et seq; Section 8 of the Public Utilities Commission Act, 1919 PA 410; MCL 460.58 et seq., Sections 6 and 6a of the Public Service Commission Act 1939 PA 3, MCL 460.6 et seq., and Section 7 of the Electric Transmission Act, 1909 PA 106, MCL 460.557 et seq.
[4515] Id., p. 2-3, citing MCL 460.6a, 460.6j, 460.6l, and 460.6m.
[4516] Id., p. 3, citing MCL 460.58.
[4517] Id., p. 3-4, citing MCL 460.557.
[4518] Id., p. 4-5, citing multiple statutes.
[4519] Id., p. 5-8, citing MCL 460.6t, MCL 460.1071, et seq, MCL 460.1171, et seq, and MCL 460.1022, et seq.

judicial authority reinforces the Commission's duty to require the adoption of VPPs.[4520] According to the GLREA:

> [T]he adoption of VPPs can directly mitigate the cost of utility service by creating a framework in which existing capacity and energy resources can be more efficiently utilized to reduce investment in generating plants such as peaking plants, can reduce PSCR costs in the form of fuel, purchased power, and transmission costs, while at the same time, VPPs can increase the reliability and resiliency of the grid and other resources necessary to service electric customers.[4521]

GLREA elaborates on Mr. Boehnke's testimony and recommendations and states that the Commission should adopt the SMART (Specific, Measurable, Achievable, Relevant, and Time-bound) framework in their order regarding VPPs to ensure that all the recommendations are enacted.[4522] GLREA also describes the Commission's prior actions to facilitate VPPs and notes that despite these efforts, Consumers' resistance has stymied the development and deployment of VPPs.[4523]

GLREA responds to Consumers' rebuttal testimony and notes that it seems geared toward undermining GLREA's contentions as opposed to offering data, research, or a pathway forward.[4524] GLREA asserts that Consumers' argument that it would be premature to impose any additional VPP requirements should carry no weight since Consumers has not been investigating the impacts of VPPs or assessing the

---

[4520] Id., p. 6-7, citing *City of Detroit v PSC*, 308 Mich 706 (1944); *Chesapeake & Ohio Railway Company v Public Service Commission*, 59 Mich 88, 94 (1975); *Consumers Power Co v Public Service Commission*, 460 Mich 148, 155-156 (1999).
[4521] Id., p. 8.
[4522] Id., p. 11-33.
[4523] Id., 9-11.
[4524] Id., p. 39.

value of EWR programs on infrastructure planning, nor has it performed an analysis regarding the financial impacts of VPPs relative to conventional infrastructure.[4525]

GLREA contends that while the California project may have been a test, it delivered 535 MW, which demonstrates the maturity of the technology to aggregate and deploy vast amounts of power.[4526] Moreover, asserts GLREA, it isn't the only deployed VPP, as the DOE's report discusses 18 VPPs supplying 30 GW of peak demand.[4527]

To Consumers' argument that VPPs must be studied to assess how they will impact Consumers' territory, GLREA agrees generally that implementing an ineffective program would be an irresponsible use of ratepayer funds, but asserts that the delivery of affordable, reliable, and resilient services to customers is also crucial to responsible stewardship of ratepayer funds and Michigan utilities have not demonstrated such stewardship, ranking last out of the 50 states and the District of Columbia in CAIDI performance and second to last in SAIDI.[4528]

As for the argument that there are no governing interoperability or integration standards for VPPs, GLREA contends that while it may be reasonable to incorporate core requirements into VPPs, Consumers is using this an excuse for its inaction.[4529]

Finally as to the contention that the Commission should not adopt modeling requirements for VPPs that apply solely to Consumers and which are outside of IRP proceedings, GLREA states that "[g]iven the advantages in cost and reliability of Virtual

---

[4525] Id.
[4526] Id., p. 42.
[4527] Id.
[4528] Id., 43, citing Michigan Utility Reliability Performance Worse Than Ever, https://cubofmichigan.org/blog/michigan-utility-reliability-performance-worse-than-ever-new-cub-report-finds, September 5, 2025.
[4529] Id., p. 45.

Power Plants over traditional generation, the Commission's mandate requires the modelling of VPPs and demand-side aggregations prior to approving rate increases to cover avoidable capital expenditures and PSCR costs."[4530]

In its brief, MEIU recaps Mr. Albers' testimony and describes and supports CEO witness Kenworthy's and GLREA witness Boehnke's testimony. MEIU recommends the Commission direct Consumers to explore a VPP program as described by the CEO and GLREA and as modified by the recommendations of Mr. Albers.[4531]

Despite the extensive authorities GLREA provided in its initial brief to support Commission action on VPPs, Consumers contends in reply that "GLREA does not identify a single Michigan statute that provides the MPSC such authority."[4532] Consumers avers that Commission authority must be founded in statute and doubtful powers do not exist.[4533] Consumers adds that the Commission's authority to regulate rates does not include the power to make management decisions.[4534]

In its reply brief, the CEO reiterates its position on VPPs and argues that Consumers is both wrong on the law, and wrong on the readiness of VPPs.[4535] The CEO asserts that Consumers fails to acknowledge that the Commission has broad authority to regulate rates under Chapter 460 of the Michigan Compiled Laws.[4536] The CEO also contends that it only recommends that Consumers be required to create a VPP plan which builds on its DR program and the Whole Home Optimization Pilot, not

---

[4530] Id., p. 45-46.
[4531] MEIU initial brief, p. 34.
[4532] Consumers reply brief, p. 30.
[4533] Id., citing *Consumers Power Co v Public Service Commission*, 189 Mich App 151, 176 (1991).
[4534] Id., citing *Union Carbide Corp. v Public Service Commission*, 431 Mich 135 (1988)
[4535] CEO reply brief, p. 2.
[4536] Id., citing *In re Consumers Energy Co*., 913 N.W.2d 406, 413 (Mich. Ct. App., Dec. 28, 2017).

to immediately deploy a VPP.[4537] And, argues the CEO, Consumers never addresses the recommendation to build a VPP program on its DR program.[4538] The CEO asserts that while Consumers addressed the viability of VPPs, its arguments are undercut by DOE's report, "Pathways to Commercial Liftoff: Virtual Power Plants." The CEO also contend that Consumers' characterization of the significance of the California test event is inaccurate and its arguments ineffective.[4539] Finally, as to Consumers' argument that it lacks the system controls to effectively manage VPPs, the CEO agrees but expects Consumers to convene the promised DERMS stakeholder group and move efficiently to propose a DERMS in its next rate case.[4540]

In its reply brief, MEIU counters Consumer's argument that the Commission has no authority over the Company's managerial decisions regarding VPPs, asserting that "the Michigan Supreme Court pointed out in [*Union Carbide*] however, the Commission may certainly deny recovery of costs incurred by Consumers when making management decisions that the Commission deems unreasonable or imprudent."[4541] Citing GLREA's initial brief, MEIU contends that the Commission has no obligation to continue to approve Consumers' recovery of investments in traditional infrastructure or costs attributable to it to the extent that VPPs provide a more cost-effective and superior alternative.[4542] MEIU reiterates its recommendation that if the Commission uses its

---

[45374537] Id., p. 2-3.
[4538] Id., p. 4.
[4539] Id., p. 3.
[4540] Id., p. 4.
[4541] MEIU reply brief, p. 2, citing *Union Carbide Corp v Public Service Com'n*, 431 Mich 135, 149-50 (1988).
[4542] Id., p. 3.

lawful authority to direct Consumers to develop VPPs, it should adopt MEIU's four recommendations.[4543]

In its reply brief, GLREA argues that taking the statutory authority as a whole, to be read harmoniously *in para materia*, the Commission can readily find that the failure of a utility to implement VPPs would be unreasonable and imprudent and would justify downward rate adjustments associated with avoidable capital investment and operational costs.[4544] GLREA elaborates on its initial brief and its witness's testimony and otherwise asserts that Consumers fails to explain its positions against VPPs or justify its delay and resistance to their timely implementation.[4545]

This PFD finds that the CEO and GLREA provided extensive support for VPPs and this PFD agrees that VPPs can provide a multitude of grid benefits, increase system reliability, and avoid or defer costly capital investments. This PFD also appreciates GLREA's extensive recitation of the Commission's authority. Nonetheless, while Consumers must meet legislatively set goals for clean energy, energy efficiency, and energy waste reduction, among other things, there is no statute which explicitly requires Consumers to invest in and develop a VPP. Moreover, a central analysis in a rate case is the reasonableness and prudence of the utility's revenue request. Since Consumers is not proposing any VPP-related costs, this PFD finds that Consumers' decision not to develop VPPs at this time is a managerial or business decision, which rests solely with the Company.

[4543] Id., p. 3-4.
[4544] GLREA reply brief, p. 2.
[4545] GLREA reply brief.

This PFD declines the CEO's, GLREA's and MEIU's call for the immediate development of a VPP proposal, as well as associated recommendations relating to a VPP tariff, design elements, measurement and verification, and a BCA. This PFD also recommends that the Commission reject the related variety of recommendations on EWR, Demand Response, DER programs, NWS, and VPP modeling, as these issues are better addressed in the DERMS workgroup or other proceedings. This PFD notes that while Consumers has not sought funding for the development of VPPs, in its last rate case it requested DERMS funding, which was rejected by the Commission due to lack of supporting evidence. The Commission stated:

Therefore, should Consumers seek recovery for a DERMS in a future electric rate case, it is incumbent on the company to provide a business case for the program, including a comprehensive BCA, that sufficiently identifies and justifies the program's costs and benefits to customers. When developing such a business case, Consumers should look at other states' best practices for examples of plans that can be readily implemented with regard to valuing the benefits of DERs and that are more actionable than the company's current proposal to hire a consultant to contract for the development of a strategy and business case. The Commission notes that development of such a business case should provide opportunities for interested persons to provide robust feedback and input into the business case and must include an analysis of the use of VPPs. The Commission encourages the company to initiate a workgroup with interested

persons and to develop more pilots or other actionable proposals to develop and further evolve the company's initial proposal.[4546]

This PFD reiterates the Commission's directives above finding them germane to the VPP issue in this case. However, this PFD recommends that the Commission add to the above by encouraging Consumers to participate in EPRI's DER Integration program and explore additional DERMS working group opportunities in other states, as Consumers indicated it was interested in doing. Furthermore, this PFD recommends the robust discussion of the following items in Consumers' DERMS workgroup: 1) integration of VPPs onto Consumers' system and technical standards; 2) whether any of Consumers' current programs can be used as launching pads for VPPs; 3) the development of a BCA for VPPs; and 4) whether the implementation of NWS is ready or needs another pilot.

L. Transmission Coordination with METC

Mr. Fleck testified on behalf of Michigan Electric Transmission Company (METC). Mr. Fleck stated that there was a pressing need in Michigan for improved regional transmission to ensure reliability but also access to low-cost energy resources. He asserted that the Commission and Consumers should continue to support MISO's LRTP Planning Process, which would encourage METC and Consumers' shared goals of reliability, system resiliency, and equitable service to customers.[4547] Mr. Fleck, on behalf of METC, urged the Commission to direct Consumers to engage in coordination with METC to assess and plan for EV charging infrastructure impacts to the current and

[4546] Case No. U-21585, Order, March 21, 2025, p. 117-118 (internal citations omitted).
[4547] 4 Tr 3189-90.

future demand needs of Consumers' service territory including transmission upgrade needs for Direct Current Fast Charging ("DCFC") deployment. He also asserted that joint planning between METC and Consumers was critical in economic development zones and electrified corridors, and in economic development zones, where coordinated infrastructure investments could accelerate grid readiness, support large-scale load growth, and enable timely interconnection for new generation projects.[4548]

METC also requested that the Commission support and approve Consumers' updates to the Reliability Roadmap as it related to transmission service.[4549] Specifically, Mr. Fleck recommended establishing a stakeholder working group to align transmission and distribution planning with state electrification goals. Input from the Commission, MISO, utilities, local governments, EVSE providers, and other community organizations were key in bringing about solutions to increasing electrification with the proliferation of EVs and broader reliability concerns in Michigan. Mr. Fleck requested the Commission support Consumers proposed TEP and Reliability Roadmap objectives, encourage active participation in MISO's regional planning process, direct formal coordination between Consumers and METC on EV infrastructure and load growth planning to maintain reliable service, and promote stakeholder engagement to align transmission investments with Michigan's energy resource mix and electrification goals.[4550]

Mr. Fleck's testimony generally indicated support for the Company's distribution plan as defined in the Reliability Roadmap and extolled the benefits of coordination between METC and the Company. However, he proposed the establishment of a

---

[4548] 4 Tr 3190.
[4549] 4 Tr 3192.
[4550] 4 Tr 3193.

stakeholder working group to align transmission and distribution planning with state electrification goals, which would represent formal coordination between the Company and METC.[4551] Mr. Kelly stated that Consumers Energy was happy to have any discussions sought by METC at their request, and the Company would engage in informal coordination (and indeed already does so in various ways). However, the Company did not believe that the Commission needs to order a formal coordination process.[4552]

In its brief, the Company expresses willingness to have any of these discussions with METC at METC's request and will continue to engage in informal coordination with METC. As such, there is no need for the Commission to order a formal coordination process.[4553]

In its brief, METC requests the Commission require Consumers to coordinate with METC regarding updates to its HVD system. Coordination is critical to its success as investments in various areas, including the HVD system and EV charging/DCFC access, rely upon cooperation with METC transmission planning. With MISO's regional planning process and future development beginning, and resource adequacy concerns for Michigan not abating, coordination between METC and Consumers (along with thorough transmission planning) must address backbone transmission and HVD investment for ensuring a reliable and resilient grid.[4554] Michigan's grid is facing increasing electrification with the proliferation of EVs, and broader reliability concerns brought on by the growing amount of large load customers. While METC believes

[4551] 3 Tr 1622.
[4552] 3 Tr 1622-23.
[4553] Company brief, p. 456.
[4554] METC brief, pp. 22-23.

Consumers' proposals in this rate case are step in the right direction in addressing these concerns, METC also believes there needs to be more coordination among stakeholders regarding transmission and distribution planning. Input from the Commission, MISO, utilities, local governments, EVSE providers, and other community organizations are key in bringing about solutions to increasing electrification with the proliferation of EVs and broader reliability concerns in Michigan. Thus, METC recommends establishing a stakeholder work group to align transmission and distribution planning with state electrification goals.[4555]

This PFD acknowledges the Company's willingness to continue information coordination with METC and recommends the Commission encourage the Company to continue to engage in information coordination with METC on the Reliability Roadmap and other aspects of the Company's distribution plan.

M. Separate Campbell Plant Docket

Mr. Coppola recommended the opening of a separate docket to address any issues related to the Department of Energy's (DOE's) order for the continued operation of the J.H. Campbell plant. He testified that Consumers indicated that it was not proposing any rate case changes due to the order but that it plans to refund any FERC-collected amounts to the extent they were collected through jurisdictional rates.[4556] He opined that given the current situation, Consumers' plan to make later refunds is the only workable solution.[4557]

[4555] METC brief, p. 28.
[4556] 3 Tr 2485; Ex. A-20.
[4557] 3 Tr 2485.

To ensure a full and proper accounting of costs and revenue from Campbell's continued operation, including any rate recovery in this case or Case No. U-21585, Mr. Coppola recommended that the Commission open a contested case proceeding "to review all aspects, impacts, cost and revenue reconciliation, and refunding of net amounts to customers."[4558]

He testified further that Consumers is requesting $17,782,000 for the bridge period and $9,600,000 for the projected test year to install a Waste Water Treatment System (WWTS) and relocate Campbell's machine shop.[4559] He surmised that the project is not ready to be included in the rate base as Consumers indicated in discovery that project is still in the planning phase of development, no design or engineering work has been completed, and the cost and timing of the project may change significantly.[4560] Mr. Coppola stated that "in light of the continued operation of the Campbell plant, the uncertainty surrounding the length and manner of its operation under FERC jurisdiction, and the still preliminary phase of development of the project," he is recommending that the costs for the WWTS be removed from Consumers' forecasted capital expenditures.[4561]

In rebuttal, Ms. Myers testified that Consumers agrees with Mr. Coppola's assessment of the situation at the Campbell plant. She confirmed that Consumers plans to request recovery of the costs associated with DOE's order through a FERC process and will refund any amounts that were collected through jurisdictional rates.[4562]

[4558] 3 Tr 2486.
[4559] Id.; Exhibit A-12, Sch.B5.2.
[4560] 3 Tr 2486; Ex. AG-21.
[4561] 3 Tr 2486-2487.
[4562] 3 Tr 1846.

However, Ms. Myers' did not agree that a new docket was necessary for Campbell. She averred that the review Mr. Coppola is calling for will be informed by the FERC process and therefore it should not take place until the FERC process has been completed.[4563] Further, she maintained that Mr. Coppola did not provide any reason why this review could not be completed as part of a future rate case filing.[4564]

Mr. Blumenstock noted in rebuttal that Mr. Coppola inaccurately presented Consumers' proposed bridge period expenditures for the Campbell WWTS. He testified that Consumers' proposed bridge period expenditures are $12.4 million rather than $17.782 million.[4565] He testified further that while the project may not be implemented before the end of the test year, Consumers intends to work on it during the bridge period and test year, despite Campbell's continued operation.[4566] He stated that "t]he continued operating status merely delays completion and project closure; it does not stop work for this project" and the capital expenditures "should not be disallowed."[4567] He added that Consumers 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.[4568]

Consumers' brief reiterates Ms. Myers' and Mr. Blumenstock's testimony, while the Attorney General reiterates Mr. Coppola's testimony and recommends the removal

---

[4563] 3 Tr 1847.
[4564] 3 Tr 1847-1848.
[4565] 6 Tr 3603; Ex. A-12, Sch. B-5.2.
[4566] 6 Tr 3603.
[4567] 6 Tr 3603-3604.
[4568] 6 Tr 3604.

of $17,782,000 and $9,600,000 for the bridge period and projected test year, respectively.[4569] Neither party addresses the issue in their reply briefs.

This PFD declines to adopt the Attorney General's recommendation to open a separate Campbell docket, agreeing with Consumers that a full and proper accounting of Campbell's costs and revenues and refunding of any necessary amounts can take place in a future rate case proceeding. As to her recommended disallowances for bridge period and test year expenditures for the WWTS, this PFD rejects the disallowances based on Consumers' statements that work on the project will still occur and capital expenditures will be offset with AFUDC so there will be no impact on rates, and also noting that the she did not challenge the necessity of the WWTS. Accordingly, this PFD recommends that the Commission reject the Attorney General's proposed disallowances of $17,782,000 and $9,600,000 for the bridge period and projected test year, respectively.

N. Accounting Requests

Consumers requests continuing regulatory asset treatment for the PowerMIDrive (PMD) and PowerMIFleet (PMF) programs; the decommissioning costs for Karn Units 1 and 2 and Campbell Units 1, 2, and 3 as well as ash disposal costs for these units and the Classic 7 sites; the remaining net book value of Campbell Units 1, 2, and 3; the Pension and OPEB Volatility Mechanism; the retention costs for Campbell units 1, 2, and 3 and Karns Units 1 and 2; and the river hydroelectric capital expenditures.[4570]

[4569] Consumers initial brief, p. 99-101, 456-457; AG initial brief, p. 87-90.
[4570] 3 Tr 1061-1068, 1832; Ex. A-12 and Exs. A-75 through A-81.

Staff did not raise any issues, and no other party took issue with the Company's above-referenced accounting requests. Accordingly, this PFD finds that Consumers' requests for continuing regulatory asset treatment as detailed above should be approved. Accounting requests for the Service Restoration Resiliency Fund and Extraordinary Storm Accounting are discussed elsewhere in this PFD.

1. SAP S4/HANA Regulatory Asset Approval

Consumers requests approval to recognize a regulatory asset to record deferred O&M expenses associated with the SAP S4/HANA project and amortize it over 15 years consistent with the life of the assets.[4571] Mr. Daly explained that the SAP S4/HANA project is crucial since the vendor will end support for the current Enterprise Resource Planning (ERP) SAP solution at the end of 2027.[4572] According to Mr. Daly, Consumers is projecting $34.8 million of test year capital spending and $15.2 million of O&M expenses for the project.[4573] He testified that deferring these expenses will prevent ratepayers from having to fund spikes in project expenses, smooth collection over the life of the asset, and provide a rate recovery period that is contemporaneous with the realization of project benefits.[4574] According to Mr. Daly, if the deferral is approved, the revenue deficiency of the case should be lowered by $14.6 million.[4575] Consumers also requests to extend the amortization period to 15 years for the cloud implementation

[4571] 3 Tr 1068-1070.
[4572] 3 Tr 1068.
[4573] 3 Tr 1069.
[4574] Id.
[4575] 3 Tr 1069; Conf. Ex. A-86.

costs for the SaaS solution creating consistency in the recovery for all aspects of the SAP S4/HANA project.[4576]

Staff witness Nichols expressed Staff's support for the requested accounting treatment to defer the SAP S/4HANA Implementation Project O&M expense. Staff recalculated the revenue deficiency impact by applying Staff's recommended cost of capital and calculated a revenue deficiency reduction that is slightly different than Consumers.[4577] Additionally, Ms. McMillan-Sepkoski testified that Staff approves Consumers' request to amortize the cloud implementation costs for the SaaS solution over 15 years.[4578]

Mr. Coppola testified that the SAP S4/HANA project is premature as the current ERP system still functions well and meets the needs of the Company and furthermore Consumers has not yet selected a vendor for the new system. He recommended that the Commission reject Consumers' deferred accounting request.[4579]

In rebuttal, Mr. Daly testified that the deferral of O&M expenses for the SAP S4/HANA project and amortization of cloud implementation costs over 15 years are necessary to align cost recovery with the period over which the project delivers benefits and help mitigate customer rate impact.[4580] He maintained that the Commission approved Consumers' request to defer SAP S4/HANA investment O&M expenses in the Company's recent gas case, Case No. U-21806. He also noted that Mr. Coppola did not

---

[4576] 3 Tr 1070.
[4577] 6 Tr 4566; Conf. Ex. S-7.
[4578] 6 Tr 4515.
[4579] 3 Tr 2499-2503.
[4580] 3 Tr 1080.

specifically criticize the accounting request, beyond his assertion that the SAP S4/HANA project was premature.[4581]

The parties' briefs largely rely on the testimony of their respective witnesses in support of their positions regarding Consumers' deferred accounting request for the SAP S4/HANA project and the 15-year amortization of the SaaS costs.

This PFD recommends approval of Consumers' accounting requests related to the SAP S4/HANA project, that is the deferral of O&M expenses and the 15-year amortization of cloud implementation costs. As discussed elsewhere, this PFD recommended approval of the SAP S4/HA capital expenditures and accordingly disagrees with the Attorney General's argument that the project is premature. This PFD finds that deferring the SAP S4/HANA project O&M costs and amortizing the cloud implementation costs for the SaaS solution over 15 years are appropriate for the reasons given by the Company, including mitigating the impacts on customer rates.

2. LVD Line Clearing Ramp-up Deferral

Consumers requests approval to recognize a regulatory asset to record deferred O&M expenses associated with the LVD Line Clearing Program Ramp-up to achieve a five-year line clearing cycle as discussed by Ms. Stewart.[4582] Mr. Daly testified that the ramp-up costs, which total approximately $256 million, represent incremental expenditures above a defined baseline in 2026 when the ramp-up begins through its completion in 2030-2031.[4583] Ms. Stewart testified that Consumers' projected baseline requirement of $164.446 million for the test period was calculated using the Company's

[4581] Id.
[4582] 3 Tr 1070-1072.
[4583] 3 Tr 1071.

projection for the annual expense needed to maintain the five-year cycle after it is achieved in 2030-2031, adjusted to test period dollars.[4584] According to Mr. Daly, if the deferral is approved, the revenue deficiency of the case should be lowered by $21.4 million.[4585]

Mr. Bleckman testified that Consumers' proposal to securitize the deferred ramp-up related expenses as a regulatory asset is conditional on the ability to receive the prevailing pre-tax weighted average cost of capital (pre-tax WACC) on the balance until the costs are securitized. He asserted that because the deferred expenses are long term, Consumers intends to fund the ramp-up with a mix of long-term debt and equity, and consequently the Company's weighted average cost of capital is the appropriate rate to apply to the regulatory asset.[4586] Additionally, he maintained that applying a pre-tax WACC is important because Consumers would be absorbing the cash and expense burden to fund the ramp-up while not collecting any of the costs from customers.[4587] He testified that if the regulatory asset was funded with short-term debt in lieu of pre-tax WACC, the Company's FFO would be lower and its debt higher, leaving the standalone FFO-to-debt ratio wholly insufficient and causing harmful credit metric impacts.[4588]

Mr. Nichols expressed Staff's support for Consumers' requested accounting treatment to defer forestry (line-clearing) ramp-up O&M expenses. He recalculated the

[4584] 3 Tr 2218-2219, Fig. 13.
[4585] 3 Tr 1072; Ex. A-82.
[4586] 3 Tr 857-858.
[4587] 3 Tr 858.
[4588] 3 Tr 858-859.

revenue deficiency impact by applying the Staff's recommended short-term debt rate and calculated a revenue deficiency reduction of $21,691,000.[4589]

Staff witness Duell contended that the rate of return on the regulatory asset should be Staff's short-term debt rate of 4.92% and not the Company's pre-tax WACC.[4590] Ms. Duell maintained that Consumers has not invested in line clearing like they should have and has continued to operate on cycle lengths longer than other peer utilities.[4591] She testified that Consumers operated on a 14.2-year line clearing cycle until 2020 when funding was approved to move to a 7-year cycle in Case No.U-20697.[4592] She also noted that Consumers' proposed 2025 work plan reveals that of the 283 circuits designated to be cleared, 77 of them were last cleared 20-37 years ago and 42 circuits were last cleared 30-37 years ago.[4593] She testified that Staff was astonished at these numbers and believes that the return on the line clearing regulatory asset should be set at Staff's short-term debt rate because Consumers failed to appropriately prioritize line clearing in the past.[4594]

Mr. Coppola agreed in principle with the LVD Line Clearing Ramp-up deferral request, however he disagreed with the proposed baseline and the rate of return for the regulatory asset. He testified that Consumers chosen baseline for the ramp-up ($164.5 million) is too high and reduces the opportunity to defer and securitize a higher amount of tree clearing costs.[4595] He maintained that while Consumers plans to officially start

---

[4589] 6 Tr 4564-4565; Ex. S-1, Sched. A-3.
[4590] 6 Tr 4389.
[4591] Id.
[4592] 6 Tr 4389-4390.
[4593] 6 Tr 4390; Ex. A-173.
[4594] 6 Tr 4390.
[4595] 3 Tr 2581.

the five-year cycle in 2026, it has already started to increase the number of miles cleared and has accelerated spending, going from $110.2 million in 2024 to $125.4 million in 2025.[4596] Based on this, Mr. Coppola asserted that the 2024 historical amount is a more reasonable baseline and he recommend that the Commission require Consumers to defer all expenses above a baseline of $110,225,000. He testified that using his recommended baseline would result in the removal of $76,459,000 from the projected test year O&M expense for line clearing and its inclusion in the regulatory asset.[4597]

As for the rate of return on the regulatory asset, like Staff, he recommended the use of the short-term debt rate, noting that the Commission found it appropriate for DTE's tree-trimming surge costs in Case No. 20162, and it is necessary to maintain consistency between the two utilities. He added that the short-term interest rate reflects the short period that the costs will be held in the regulatory asset and will provide an added incentive to securitize the costs sooner than later.[4598] Using the 4.92% short-term rate, he calculated the proposed return at $1,811,000.[4599]

CUB witness Bunch agreed that line clearing ramp-up (or surge) costs should be held as regulatory assets but, like Mr. Coppola, he disagreed with Consumers' defined baseline and ramp-up amount.[4600] He testified that the baseline, which was supported by Company witness Stewart, is speculative and novel as it projects future expenses

---

[4596] 3 Tr 2581-2582.
[4597] 3 Tr 2582.
[4598] 3 Tr 2593.
[4599] 3 Tr 2593; Ex. AG-59.
[4600] 6 Tr 4052.

and then works backward to develop the baseline.[4601] He proposed using 2024 historical levels adjusted by a productivity-adjusted inflation (PAI) rate, to determine baseline, or test year, spending of $113,977,000. He explained that the difference between Consumers' proposed spending of $186,684,000 and his baseline is $72,707,000 which represents the surge, or ramp-up, and should be treated as a regulatory asset and removed from O&M expense.[4602]

In rebuttal, Mr. Daly testified that the approaches taken by Mr. Coppola and Mr. Bunch to establish the baseline are "overly simplistic and fail[s] to reflect the operational and strategic planning embedded in Consumers' acceleration to a five-year LVD line clearing cycle."[4603] He asserted that their reliance on 2024 historical spending ignores the evidence that the cost of the ramp-up is significantly higher than maintaining historical levels of expense when Consumers was on a seven-year cycle.[4604] And he maintained that their approach disregards forward-looking changes that are appropriately considered in a projected test year, and appear designed to suppress the test year "baseline," thereby limiting Consumers' ability to recover a substantial portion of O&M costs.[4605] He asserted that it would be unreasonable to set the baseline level below currently authorized spending levels, as their proposals would do, particularly as Consumers transitions to a more aggressive five-year cycle.[4606] He pointed out that there has been a consistent upward trend in both actual and authorized forestry

---

[4601] 6 Tr 4052-4053.
[4602] 6 Tr 4053.
[4603] 3 Tr 1083.
[4604] Id.
[4605] 3 Tr 1083-1084.
[4606] 3 Tr 1085.

spending in Consumers' five most recent rate cases, which reveals the unreasonableness of Mr. Coppola's and Mr. Bunch's baselines.[4607]

Mr. Bleckman responded to Ms. Duell's recommendation to set the rate of return for the regulatory asset at Staff's short-term debt rate of 4.92%. He asserted that her attempt to justify the short-term interest rate by referencing the Commission approved rate for DTE's tree-trimming surge program is inappropriate.[4608] He maintained that the current risk environment has experienced a material change that should be considered, as well as the impact on cash flow and the credit metrics of Consumers' numerous cost deferral mechanisms.[4609] He testified that Staff's justification for the short-term debt rate, that Consumers hasn't invested in line clearing like it should have, is unreasonable and appears punitive. According to him, in taking this approach, Ms. 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."[4610] As for the alternative baselines proposed by Mr. Coppola and Mr. Bunch, Mr. Bleckman noted that they would place undue additional pressure on Consumers' credit metrics as a result of lower cash and higher financing.[4611]

Ms. Stewart also provided rebuttal testimony to Ms. Duell regarding Consumers' past line clearing program. She asserted that Consumers has been transparent about its line-clearing backlog and since Case No. U-20697 has been committed to reducing

---

[4607] Id.
[4608] 3 Tr 865.
[4609] 3 Tr 865.
[4610] 3 Tr 866.
[4611] 3 Tr 867.

the cycle length, which demonstrates its prioritization of the program.[4612] Ms. Stewart also responded to Mr. Coppola's and Mr. Bunch's testimony regarding the ramp-up baseline. She clarified that 2026 will be a transitional year in the ramp-up process, with the Company operating under a 7-year cycle for the first four months and the remaining eight months reflecting the ramp up to the 5-year cycle.[4613] As a result, she maintained that the baseline operational expense for 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 projected for 2026.[4614]

In her rebuttal testimony, Ms. Duell expressed Staff's opposition to Mr. Coppola's and Mr. Bunch's baseline proposals. According to Ms. Duell, Staff's position is that the Commission should approve the full proposed spend of $186,683,974 in Line Clearing O&M requested by Consumers, with $164,445,867 being recovered as base O&M expense and $22,238,107 being recovered as part of a regulatory asset.[4615] She testified that using Consumers' proposed baseline for the ramp-up should ultimately result in less expense going into the regulatory asset over the next five years, which would mean lower interest expense to ratepayers in the long run compared to Mr. Coppola's and Mr. Bunch's proposals.[4616]

In briefing, the parties generally repeat their respective witnesses' testimony and respond to pertinent rebuttal testimony. Consumers continues to argue that its LVD Line

---

[4612] 3 Tr 2237-2238.
[4613] 3 Tr 2243-2244.
[4614] 3 Tr 2244.
[4615] 6 Tr 4409.
[4616] 6 Tr 4409-4410.

Clearing Ramp-up baseline is the most reasonable and the pre-tax WACC is the most appropriate rate of return on the regulatory asset, while the Attorney General maintains her recommendation to use a lower baseline and the short-term interest rate.[4617]

Staff's brief maintains its position that the Commission approve recovery of $22,238,107 in a regulatory asset for line clearing, but at Staff's short-term debt rate of 4.92%, not Consumers' pre-tax WACC.[4618] Staff notes that in each case the Commission orders the short-term debt rate it finds reasonable based on the record, and in DTE's last rate case the Commission ordered that DTE's return on its tree trimming surge regulatory asset be set at Staff's short-term debt rate of 5.73%.[4619] Staff argues that the Commission should order the same for Consumers and such treatment is warranted as the Company has circuits that have not been cleared in over 30 years.[4620]

MNSC contends its proposed ramp-up baseline is reasonable as it is based on applying known and reasonable increases (productivity-adjusted inflation) to historical (2024) spending.[4621] MNSC explains that the Commission has expressed a preference for such a method, "finding that a 'properly adjusted historical test year provides a firm, prudent, and practical basis for setting appropriate rates for the future period.'"[4622] MNSC argues further that it is of "no consequence" that its proposed baseline is below 2025 approved levels since "[t]he Company's current and historic line clearing plans

---

[4617] Consumers initial brief, p. 331-336; AG initial brief, p. 177-178, 197-198.
[4618] Staff initial brief, p. 138.
[4619] Id., citing Case No. U-21534, Order, January 23, 2025, p. 227.
[4620] Id., p. 138-139.
[4621] MNSC initial brief, p. 138-141.
[4622] Id., p. 138, citing Case No U-13898, Order, April 28, 2005, pp 10-11.

includes catching up the backlog of circuits, so the current approved spending levels reflect the cost of catching up."[4623]

As for Staff's concerns that its proposed baseline would cause more expense to go into the regulatory asset, MNSC counters that Consumers' baseline would raise operating expenses, which are not amortized, and cause more immediate impacts to customers' rates.[4624] MNSC maintains that its proposed LVD Line Clearing Ramp-up baseline would mitigate rate impacts to struggling customers by deferring a realistic estimate of surge spending.[4625]

MNSC further contends that Consumers' concerns about its credit metrics are unsubstantiated, noting that, as filed, the FFO-to-Debt ratio of the deferral as a *standalone* would be approximately 18% if the pre-tax WACC is applied, whereas the FFO-to-Debt ratio would be approximately 5% if the asset balance is assumed to be financed with short-term debt.[4626] MNSC argues further that Consumers does not provide evidence to support its contention that the short-term debt rate would cause harmful credit impacts or result in a credit downgrade.[4627]

In its reply brief, Consumers rejoins MNSC's argument that the Commission prefers using historical test years adjusted for known and measurable changes as stated in Case No. U-13898. Consumers notes that the order in Case No. U-13898 predates Public Act 286 of 2008 and Case No. U-15645, where the Commission expressed support for projected test years and suggested that historical numbers may

---

[4623] Id., p. 140.
[4624] Id., p. 141.
[4625] Id., p. 142.
[4626] Id., p. 144-145.
[4627] Id., 145-146.

be outdated.[4628] Consumers argues that the baseline amounts proposed by MNSC and the Attorney General are "outdated" and should be rejected because they disregard the fundamental shift in operations to transition to a five-year LVD line clearing cycle.[4629]

As there are no disputes regarding Consumers' request to defer Line Clearing Ramp-up costs to attain a five-year clearing cycle, this PFD recommends approval of this request. As for the amount to be deferred, this PFD agrees with Consumers and Staff and recommends that $22,238,107 be recovered as part of a regulatory asset based on the Company's proposed spending of $186,683,974, as discussed in the O&M section, with baseline (test year) spending of $164,445,867. This PFD finds that Consumers has adequately supported its proposed test year spending as necessary to fund the transition to a five-year line clearing cycle and agrees with Staff that it is desirable to reduce ratepayers' exposure to interest expense. This PFD declines to adopt the Attorney General's or MNSC's proposed baselines considering the consistent upward trend in Consumers' forestry spending.

Turning to the rate of return for the regulatory asset, this PFD agrees with Staff, the Attorney General, and MNSC that the short-term debt rate is appropriate. This PFD notes that the Commission approved the short-term debt rate for DTE's tree-trimming surge and despite the Company's arguments, there is no reason to use a different rate for Consumers' line clearing ramp-up. This PFD does not consider Consumers' past line clearing history as relevant when determining the appropriate return on the ramp-up regulatory asset. This PFD recommends that the Commission use the short-term debt

[4628] Consumers reply brief, p. 16, quoting Case No. U-15645, Nov. 2, 2009, p. 6 ("[w]hat is gained by dealing with data that is 'known and measurable' can be lost in forcing a utility to operate with outdated numbers.").
[4629] Consumers reply brief, p. 16.

rate it considers most reasonable until the company has arranged for securitization of the Line Clearing Ramp-up costs.

3. Surge Capital Spending on Pole Replacements

CUB-NRDC witness Jester recommended that Consumers surge capital spending on LVD pole replacements.[4630] He testified that Company witness Partlan's testimony revealed a growing backlog of poles needing replacement and Consumers is projecting spending $127.5 million in the test year for pole replacement in contrast to $22.28 million annually for the bridge period.[4631] He recommended that the Commission deem pole replacement costs that exceed $25 million in the test year to be surge costs and order Consumers to defer and propose to securitize the surge spending.[4632]

In rebuttal, Mr. Daly disagreed with Mr. Jester's pole replacement surge proposal. He maintained that Consumers generally reserves securitization for the recovery of stranded costs and the decision to propose securitization for the forestry ramp up was made to mitigate the rate impacts and spread the cost to customers more evenly over the time horizon of the anticipated benefits.[4633] He added that line clearing is a recurring operational expense, while pole replacements are capital investments resulting in long-lived assets that provide long-term benefit to customers. He testified that these expenses should be included in Consumers' permanent capital structure and be recovered through traditional rate base treatment, allowing for depreciation over time and proper cost allocation across the customers who benefit.[4634]

[4630] 6 Tr 3995-3997.
[4631] 6 Tr 3996-3997.
[4632] 6 Tr 3997.
[4633] 3 Tr 1086.
[4634] Id.

Consumer's brief recaps Mr. Daly's testimony and recommends that the Commission reject Mr. Jester's recommendation to surge LVD pole replacement expenses.[4635]

In its brief, MNSC emphasizes that it does not oppose Consumers' proposed spending of $29,711,000 in the bridge period and $127,500,000 in the test year, but disputes how it should be accounted.[4636] MNSC contends that Consumers' argument that operating expenses, like LVD line clearing, can be securitized but, capital expenses like poles, cannot, makes an artificial distinction.[4637] MNSC avers that the statute that authorizes securitization, PA 142 of 2000, MCL 460.10h-460.10z, does not restrict securitization as Consumers contends.[4638] The intent of securitization, argues MNSC, is to mitigate rate impacts to customers beyond the benefits of depreciation and reduce the total amount recovered from ratepayers relative to traditional cost recovery, whether the costs incurred are expense or capital.[4639] MNSC emphasizes that the cost of financing the pole replacement surge through securitization will be considerably less than Consumers' authorized weighted cost of capital and help to mitigate rate impacts.[4640]

In reply, Consumers rejoins MNSC's arguments that the distinction between capital and O&M costs is "artificial" and Act 142 does not limit securitization. Consumers argues that the distinction between capital and O&M is that O&M is not normally spread over several years, while capital expenditures are depreciated over time and allocated

---

[4635] Consumers initial brief, p. 51-52.
[4636] MNSC initial brief, p. 6.
[4637] Id., p. 143.
[4638] Id.
[4639] Id.
[4640] Id., p. 144.

across the customers who benefit from the expenditures. Consumers also points out that Act 142 does not require securitization but makes it available for the Company if requested.[4641]

This PFD declines to adopt MNSC's proposal to create a regulatory asset and defer pole replacement "surge" costs, finding it insufficiently justified and supported. This PFD also notes that the Company has numerous existing cost deferral mechanisms and adding more debt and interest expense without sufficient justification and a detailed record would be imprudent.

O. Wire Down

Staff witness Duell testified that Mr. Snider explained the Company's wire down procedure in discovery response U21870-ST-CE-0109 and noted that Bright Yellow "Caution Do Not Enter" tape was used to secure wire downs.[4642] She also noted that Staff recently learned from the Company that they do not have enough resources to allow personnel to stand by every wire down after a storm occurs, but tape the Company uses does not give the public any indication of what may be behind the taped-off area or why they are not supposed to be entering the area taped off. She expressed concern that members of the public would see "Caution Do Not Enter" on tape placed by Consumers Energy and think that it may not be too big of a risk to enter, not realizing there was a dangerous live wire or wires behind the tape.[4643] Therefore, she noted that Staff recommended the Company change their caution tape to one that stated "Caution

[4641] Consumers reply brief, p. 2-3, citing MCL 460.10i(1).
[4642] 6 Tr 4403-04.

[4643] 6 Tr 4404-05.

Live Wire" or "Danger Live Wire Keep Away," which would be consistent with the practices of DTE. If the Company switched their caution tape to one like DTE's then the public would know to stay away because of a downed wire. The public's safety should be the Company's upmost priority, so changing the caution tape to one that stated "caution live wire stay away" or something similar could aid in the Company's efforts to keep their customers safe.[4644]

In rebuttal, Mr. Snider stated that the Company agreed with Staff's recommendation to change the caution tape used for downed wires from "Caution Do Not Enter." Once a location has been barricaded with caution tape, a representative should be standing guard until the source has been verified de-energized. However, the Company appreciated and agreed to adopt the recommendation to utilize caution tape that indicated the potential of a live wire.[4645]

This topic is not mentioned in the Company brief.

In its brief, Staff reiterated relevant testimony and recommends the ALJ and Commission adopt Staff's recommendation that Consumers change their wire down tape to one that states "Caution Live Wire" or "Danger Live Wire Keep Away" when the Company is securing a wire down.[4646]

This recommendation is uncontested; therefore, this PFD recommends the Commission adopt Staff's recommendation that Consumers change their wire down tape to one that states "Caution Live Wire" or "Danger Live Wire Keep Away" when the Company is securing a wire down.

[4644] 6 Tr 4405.
[4645] 3 Tr 2175.
[4646] Staff brief, pp. 198-99.

XI.

CONCLUSION

Based on the foregoing discussion, this PFD recommends that the Commission adopt the findings, conclusions, and recommendations set forth above, including the findings and recommendations on rate base, capital structure, cost of capital, and operating revenues and expenses as well as recommendations regarding various accounting requests, cost of service allocations, and rate design, and including recommendations for additional Commission investigation, and additional utility reporting and analysis.

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES
For the Michigan Public Service Commission

Jonathan F. Thoits

Digitally signed by: Jonathan F. Thoits
DN: CN = Jonathan F. Thoits email = ThoitsJ@michigan.gov C = US O = MOAHR OU = MOAHR - PSC
Date: 2026.01.29 15:08:42 -05'00'

Jonathan F. Thoits
Administrative Law Judge

Issued and Served:
January 29, 2026

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

STATE OF MICHIGAN)
) SS.
County of Ingham)
_____)

Case No. U-21870

PROOF OF SERVICE

Meaghan Dobie being duly sworn, deposes and says that on January 29, 2026, she served a copy of the attached Notice of Amended Proposal for Decision and Amended Proposal for Decision via email and/or first-class mail, to the persons as shown on the attached service list.

Meaghan Dobie

Subscribed and sworn to before me this
29th day of January 2026.

Brianna L. Brown
Notary Public, Gratiot County, Michigan
My Commission Expires July 4, 2028

Case No. U-21870
Service List

CONSUMERS ENERGY COMPANY
Gary A. Gensch Jr.
Anne M. Uitvlugt
Evan B. Keimach
Spencer A. Sattler
Bret A. Totoraitis
gary.genschjr@cmsenergy.com
anne.uitvlugt@cmsenergy.com
evan.keimach@cmsenergy.com
spencer.sattler@cmsenergy.com
bret.totoraitis@cmsenergy.com
mpsc.filings@cmsenergy.com

MICHIGAN PUBLIC SERVICE COMMISSION (MPSC) STAFF
Daniel E. Sonneveldt
Amit T. Singh
Nicholas Q. Taylor
Alena M. Clark
Adam M. Cozort
Michael J. Orris
Lori Mayabb, case coordinator
sonneveldtd@michigan.gov
singha9@michigan.gov
taylorn10@michigan.gov
clarka55@michigan.gov
cozorta1@michigan.gov
orrism@michigan.gov
mayabbl@michigan.gov

DEPARTMENT OF ATTORNEY GENERAL
Celeste R. Gill
Lucas Wollenzien
gillc1@michigan.gov
wollenzienl@michigan.gov
AG-ENRA-Spec-Lit@michigan.gov

ADVANCED ENERGY UNITED;
ENERGY MICHIGAN, INC.;
FOUNDRY ASSOCIATION OF MICHIGAN;
INSTITUTE FOR ENERGY INNOVATION;

MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL
Laura A. Chappelle
Timothy J. Lundgren
Justin K. Ooms
lachappelle@varnumlaw.com
tjlundgren@varnumlaw.com
jkooms@varnumlaw.com

ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY (ABATE)
Stephen A. Campbell
Michael J. Pattwell
Benjamin J. Holwerda
James Dauphinais, consultant
scampbell@clarkhill.com
mpattwell@clarkhill.com
bholwerda@clarkhill.com
jdauphinais@consultbai.com

CITIZENS UTILITY BOARD OF MICHIGAN;
MICHIGAN ENVIRONMENTAL COUNCIL;
NATURAL RESOURCES DEFENSE COUNCIL;
SIERRA CLUB
Christopher M. Bzdok
John R. Liskey
Tracy Jane Andrews
Holly L. Hillyer
Sean C. Clark
Natasha Fowles, legal assistant
chris@tropospherelegal.com
john@liskeypllc.com
tjandrews@tropospherelegal.com
holly@tropospherelegal.com
sean@tropospherelegal.com
natasha@tropospherelegal.com

HEMLOCK SEMICONDUCTOR OPERATIONS, LLC;
SOLAR TECHNOLOGY LLC
Jennifer U. Heston
jheston@potomaclaw.com

GREAT LAKES RENEWABLE ENERGY ASSOCIATION
Don L. Keskey
Brian W. Coyer

donkeskey@publiclawresourcecenter.com
bwcoyer@publiclawresourcecenter.com

ENVIRONMENTAL LAW & POLICY CENTER;
THE ECOLOGY CENTER;
UNION OF CONCERNED SCIENTISTS, INC.;
VOTE SOLAR
Daniel H.B. Abrams
Katie Duckworth
Alondra Estrada, paralegal
Katie Toolan, legal assistant
dabrams@elpc.org
kduckworth@elpc.org
aestrada@elpc.org
MPSCDocket@elpc.org
ktoolan@elpc.org

MICHIGAN CABLE TELECOMMUNICATIONS ASSOCIATION
Sean P. Gallagher
sgallagher@fraserlawfirm.com

MICHIGAN ELECTRIC TRANSMISSION COMPANY, LLC
Richard J. Aaron
Courtney F. Kissel
Olivia R.C.A. Flower
Hannah E. Buzolits
Josh L. Kluzak
raaron@dykema.com
ckissel@dykema.com
oflower@dykema.com
hbuzolits@dykema.com
jkluzak@dykema.com

WALMART, INC.
Melissa M. Horne
mhorne@hcc-law.com

ANONYMOUS CUSTOMER A
Valerie J.M. Brader
valerie@rivenoaklaw.com

URBAN CORE COLLECTIVE
Amanda Urban
Mark N. Templeton
Jacob R. Schuhardt
aurbanlaw@gmail.com
templeton@uchicago.edu
jschuhardt@uchicago.edu

THE KROGER COMPANY
Kurt J. Boehm
Jody Kyler Cohn
Michael L. Kurtz
Justin Bieber, consultant
kboehm@bkllawfirm.com
jkylercohn@bkllawfirm.com
mkurtz@bkllawfirm.com
jbieber@energystrat.com