TROPOSPHERE LEGAL

December 5, 2025

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
Lansing, MI 48909

Via E-File

RE: MPSC Case No. U-21870

Dear Ms. Felice:

Attached please find the enclosed documents for filing:

- Initial Brief by Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan; and
- Proof of Service.
- Please note that there is a confidential version of this Initial Brief filed under seal and will only be served to those with an executed non-disclosure certificate pursuant to the Protective Order.

Thank you for your assistance in this matter. If you have any questions, please feel free to contact me.

Sincerely,

Digitally signed by Christopher M. Bzdok
Date: 2025.12.05 16:35:19 -05'00'

Christopher M. Bzdok
chris@troposphereleg al.com

CC: Parties to Case No. U-21870

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

INITIAL BRIEF BY

MICHIGAN ENVIRONMENTAL COUNCIL,
NATURAL RESOURCES DEFENSE COUNCIL, SIERRA CLUB, AND
CITIZENS UTILITY BOARD OF MICHIGAN

PUBLIC VERSION

December 5, 2025

Table of Contents

I. INTRODUCTION

In this case, Consumers Energy seeks a rate increase of $460.3 million – $436 million in base rates for its claimed revenue deficiency for the projected test year ending April 30, 2027, plus $24.3 million for a distribution deferral to be recovered through a 12-month surcharge.[1] Consumers also asks the Commission to raise its ROE from the 9.90% approved in Case No. U-21585 to 10.25%.[2]

The Michigan Environmental Council (MEC), Natural Resources Defense Council (NRDC), Sierra Club, and Citizens Utility Board of Michigan (CUB) (collectively, MNSC) present their positions on the following issues listed in the order they appear in this brief:

- Distribution Capital Spending. MNSC recommends the Commission reduce the Company's proposed test year investment in LVD undergrounding by $15.4 million. The Company should focus on the most cost-effective projects, which represent 11.3 miles out of the Company's proposed 50 miles for undergrounding.
- Jackson Plant Capital Expenditures. The Commission should disallow inclusion in rate base of capital expenditures for two projects at the Jackson gas plant for which Consumers provided insufficient support to show they are economically beneficial.
- Fleet Capital Expenditures. MNSC recommends that the Commission direct the Company to revise its internal fleet electrification target so that all light-duty vehicle replacements are electric by 2030.
- Transportation Electrification Plan (TEP) Expenditures. MNSC strongly supports the Company's Transportation Electrification Plan (TEP) proposals and recommends that the

[1] Application, p 2.

[2] *Id.* at 3.

Commission approve them with targeted modifications as detailed in NRDC, Sierra Club, and CUB witness Douglas Jester's testimony.

- Capital Structure. Consumers seeks approval to move from its current capital structure of 50% debt and 50% equity approved in Case No. U-21585 to an equity ratio of 50.75%. MNSC, along with the Commission Staff, the Attorney General, and ABATE, recommend the Commission maintain Consumers' current balanced capital structure.
- Return on Equity (ROE). Consumers seeks an increase in its ROE from the current 9.90% approved in Case No. U-21585 to 10.25%. The Commission Staff, the Attorney General, ABATE, and MNSC opposed Consumers' request and submitted their own cost of equity analyses and recommendations. Walmart also addressed Consumers' request. MNSC recommends that the Commission reject Consumers' requested ROE and authorize an ROE of 9.22%.
- Service Restoration Resiliency Fund (SRRF). Consumers proposes to create a fund that, in test years where the Company underspends on service restoration, reserves up to $30.7 million and refunds any remaining dollars to customers. MNSC opposes Consumers' proposal and asks the Commission to reject it.
- Extraordinary Storm Accounting (ESA). Consumers proposes to defer service restoration costs in years when the Company overspends on "extraordinary storms" that cause at least 300,000 customer outages over a seven-day period or result in a State of Emergency declaration from the Governor's office. MNSC opposes Consumers' proposal and asks the Commission to reject it. However, if the Commission finds merit in Consumers' ESA proposal, MNSC supports the Attorney General's recommendation to explore ESA and other deferral accounting opportunities in a separate docket.

- Inflation Rates and Productivity. Consumers responded in this proceeding to the Commission's directive in Case No. U-21585 to demonstrate how it accounts for productivity gains to offset inflation with non-responsive testimony and little new detail. Given the prior directive and the Company's presentation, CUB witness Bunch recommends that the Commission disallow $59.5 million from test year O&M expenses as a result of adjusting inflation factors by productivity offsets.
- Distribution Cost Allocation – Voltage Differentiation. The Company seeks to change the method for allocating distribution plant by allocating costs solely to the voltage levels downstream of distribution assets, rather than the voltage levels of the assets – even while denying that this change is a change. The Commission should disapprove this change in method because Consumers has not demonstrated that it reflects cost causation or is just and reasonable.
- Distribution Batteries Cost Allocation. Consumers should allocate distribution battery costs to all distribution customers, not just those at the lowest voltage levels on the system.
- IT Cost Allocation – Multi-Account Online Account Management project. Consumers should allocate the cost of the MAOAM project to commercial and industrial customers because they are the only customers who currently use it.
- Data Center Cost Allocation. MNSC made recommendations in this case concerning data center cost allocation. The Commission has since addressed the issues in its Order in Case No. U-21859.
- AMI Cost Allocation. Consumers should allocate the costs of advanced metering infrastructure to all customers in proportion to its relative benefits, which include system-wide energy and demand benefits.

- Large Economic Development Rate. The LED rate provides excessive and unreasonable discounts to LEDR customers that are not based on cost of service and that require other customers to subsidize these large customers, in service of vaguely defined and weakly evidenced economic development objectives. Consumers seeks to exacerbate the situation by adding another discount – a facilities allowance – the LED rate and applying it retroactively to existing LEDR customers. The Commission should deny these requests because they are neither just and reasonable nor do are they based on costs of service. The Commission should also increase the miniscule system contribution charge in the LED rate because it is not just, reasonable, or based on costs of service. Finally, the Commission should shorten the 15- to 20-year length of LED rate contracts because they are an outlier nationally and it is not plausibly necessary to provide discounts for such a longe period of time to induce economic development.
- Investment Recovery Mechanism (IRM). Consumers seeks an increase over the Year 2 IRM spending levels approved in Case No. U-21585 of $266 million in each of Years 3 and 4. ABATE recommends reducing the amount of Consumers' proposed annual authorized amounts for LVD Lines Reliability by at least $108.8 million per year. MNSC concurs and supports ABATE's recommendation.
- Electric Heating / Heat Pump Rate. MNSC recommends that the Commission direct Consumers to develop an electric heating (EH) or heat pump (HP) rate for presentation in its next filed rate case. Heating electrification is a key strategy for achieving Michigan's climate goals but Consumers' current rates discourage it. Consumers has expressed that it is willing to explore the development of such a rate.

- Tree trimming and LVD Pole Replacement Surge Spending. MNSC recommends regulatory asset treatment and subsequent securitization of the Company's increased spending to ramp up forestry work and LVD pole replacements over and above baseline spending, where baseline spending is generally 2024 historic levels with production-adjusted inflation to the test year.

II. RATE BASE

A. Distribution Capital Expenditures

1. Pole Maintenance – The Commission should approve the Company's proposal to catch-up on its significant backlog in LVD pole replacements, with cost recovery through securitization.

MNSC believe the following is the record on this issue: Revised Direct Testimony of Consumers witness Jennifer M. Partlan, 3 Tr 1947-51, and her sponsored exhibits A-166 to A-169; Direct Testimony of MNSC witness Douglas B. Jester, 6 Tr 3995-97; Revised Direct Testimony of MNSC witness Richard J. Bunch, 6 Tr 4054-55, 4060, and 4072, and his sponsored exhibit CUB-26; and Direct Testimony of ABATE witness Colin T. Fitzhenry, 6 Tr 3721-23 and his exhibit AB-4.

MNSC does not dispute the Company's proposed pole replacement work, which is generally consistent with the recommendations in the Liberty Audit. In the Audit, which was completed in 2024, Liberty found a "significant backlog in pole replacement and recommended catch-up investments."[3] Notably, in the last rate case – Case No. U-21585 – the Company only proposed replacing 1,666 poles in that case's bridge period and 149 poles in its test period.[4] The Company now proposes to replace 3,076 poles in this case's bridge period and 12,500 poles in the projected test year – a significant increase above historic levels.

[3] See Bunch Direct, 6 Tr 4054.

[4] Bunch Direct, 6 Tr 4054 (citing Case No. U-21585, Direct Testimony of Donald A. Lynd, 4 Tr 579, Figure 39).

To achieve its pole replacement targets, the Company seeks approval of $29,711,000 for this case's bridge period and $127,500,000 for the projected test year. MNSC raises no dispute about whether this spending should be approved, only how it should be accounted, which is addressed below in Section VII.D., "Securitization of Test Year Tree Trimming, LVD Pole Spending."

2. LVD Overhead To Underground Conversions

MNSC believe the following is the record on this issue: Direct Testimony of Consumers witness Michael P. Kelly, 3 Tr 1431-1440; Direct Testimony of Consumers witness Jennifer M. Partlan, 3 Tr 1985-1994, and her sponsored exhibits A-166 to A-169; Public Direct Testimony of AG witness Sebastian Coppola, 3 Tr 2438-43, and his sponsored exhibit AG-5; Direct Testimony of CUB witness Richard J. Bunch, 6 Tr 4060-65, and his sponsored exhibit CUB-27, CUB-29, and CUB-30; Direct Testimony of ABATE witness Colin T. Fitzhenry, 6 Tr 3725-29; Rebuttal Testimony of Consumers witness Kelly, 3 Tr 1586-01, and 1615-16; Rebuttal Testimony of Consumers witness Partlan 3 Tr 2053-57.

In this case, Consumers proposes to replace 50 miles of overhead low-voltage distribution (LVD) lines with underground lines at an average cost of $400,000 per mile.[5] The Company's proposal comes after the Commission rejected a similar proposal to underground 25 miles of LVD lines in the last rate case (Case No. U-21585).[6] The Company claims that these undergrounding projects are cost-competitive with other non-undergrounding options and will greatly improve grid reliability, as reflected in customer outage minutes.[7] While it is true that Consumers' undergrounding program may yield certain reliability benefits, the Company did not study the expected benefits of individual projects.[8] CUB witness Bunch did such an analysis, and his work

[5] Kelly Direct, 3 Tr 1439 ("The Company is proposing 50 miles of undergrounding in the test year.").

[6] Case No. U-21585, Order, March 21, 2025, p 84.

[7] Kelly Direct, 3 Tr 1436.

[8] Bunch Direct, 6 Tr 4061.

shows that the majority of expected benefits can be realized from a small minority of Consumers' proposed projects.[9] 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.[10]

a. The costs and benefits of individual undergrounding projects are highly variable.

Consumers witness Kelly testified in support of the Company's proposed $20 million undergrounding plan, which would include 28 new undergrounding projects in the test year.[11] Kelly estimated that the Company's undergrounding plan could improve circuit reliability by 90% and that it could do so in a cost-effective manner, as evidenced by the Company's cost-benefit analysis.[12]

While it is likely that the Company's undergrounding plan may provide some reliability benefits,[13] the costs and benefits of individual undergrounding projects are highly variable and cannot be easily generalized. Company data shows that reliability benefits – measured as customer outage minutes avoided – range from about 22,000 minutes to 436,500 minutes per year depending on the project.[14] Using Company data, witness Bunch calculated the present value for individual projects and determined that over half of residential customer benefits can be "realized from only

[9] *Id*. at 4062-64.

[10] *Id*. at 4065.

[11] Kelly Direct, 3 Tr 1439.

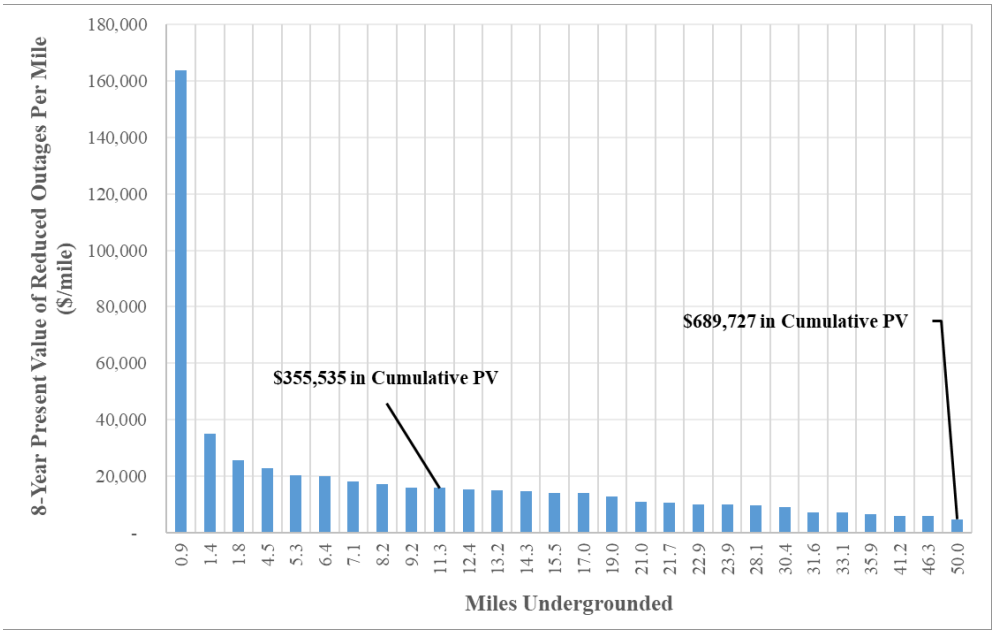
[12] See Kelly Direct, 3 Tr 1434 and 1438.

[13] Witness Bunch determined the eight-year present value of avoided outages for residential customers, which totaled $689,700 for the entire proposed program. Bunch Direct, 6 Tr 4062.

[14] Bunch Direct, 6 Tr 4062 (citing Company Ex A-167 (JMP-2), p 21).

11.3 of the 50 miles of undergrounding proposed."[15] Witness Bunch's Figure 3, copied below, shows the diminishing returns of Consumers' undergrounding program as it is scaled up.

Figure 3. Economic Benefits of Proposed Undergrounding[16]



If Consumers' undergrounding proposal is scaled to only the highest impact projects, the Company can still achieve meaningful reliability benefits for a fraction of the cost.

b. Consumers did not sufficiently justify its proposals to increase undergrounding projects in the test year and beyond.

Witness Bunch and AG witness Coppola both raised concerns about the reasoning and analysis behind the Company's proposed plan. To support its current proposal, the Company evaluated the aggregate benefits of all 28 proposed projects but did not evaluate each project individually. That approach is deeply flawed. As discussed, the benefits of undergrounding projects

[15] Bunch Direct, 6 Tr 4062-63 (providing the majority of benefits for less than 23% of Consumers' proposed costs).

[16] Bunch Direct, 6 Tr 4064 (citing Ex CUB-30, Sorted Benefits).

are highly variable and unevenly distributed among the proposed projects.[17] As witness Coppola testified, so too are the costs of proposed projects: "5 of the 8 projects in the [previous] pilot program, or 63%, had a cost that was above the average cost from 20% to 126% above the average cost."[18] When individual projects are aggregated for purposes of a programmatic cost-benefit analysis, the results are easily skewed by the most cost-effective projects.

In rebuttal, the Company explained that it did not produce individual cost-benefit analyses because, allegedly, it was not required to produce such analyses. The Company cites the Commission's June 12, 2025, Order in Case No. U-21305, which reads:

> The Commission finds that additional evidence, including a BCA, is necessary to fully evaluate the proposed undergrounding and how it compares with other potential pathways to improved reliability performance, and encourages the company to review the results of its pilot and future plans with the Staff, including the circuit selection criteria.[19]

Consumers' argument is that the words "including *a* BCA" imply that the Commission needs no more than one BCA to fully evaluate an undergrounding proposal.[20] That is not correct – 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. In Case No. U-21305, the Commission stated that it was "skeptical of the costs of the undergrounding pilot at scale" and that it needed enough additional evidence to "fully evaluate the proposed undergrounding" against other reliability programs.[21] Moreover, the

[17] Bunch Direct, 6 Tr 4062.

[18] See Coppola Direct, 3 Tr 2440-41.

[19] Case No. U-21305, Order, June 12, 2025, p 27.

[20] Kelly Rebuttal, 3 Tr 1395.

[21] Case No. U-21305, Order, June 12, 2025, p 27.

Commission requested a BCA to evaluate "the proposed undergrounding," suggesting the Company should evaluate the cost-effectiveness of each component project – the circuits proposed for undergrounding. Without individual BCAs for individual undergrounding projects, it is impossible to evaluate proposed undergrounding against other reliability programs on an apples-to-apples basis. For example, a programmatic BCA could indicate that the undergrounding program is competitive with other non-undergrounding options even if many individual undergrounding projects are not.[22] The fact that a program is benefit-cost-positive also does not mean each circuit in the program is benefit-cost-positive, as evidenced by the significant variability between circuits. Moreover, even if every circuit in the program were BCA-positive, that does not mean the Company should complete every circuit – cost restraints require the Company to prioritize the circuits that would provide the most reliability benefits per dollar. It is simply unreasonable to proceed with the full investment in all circuits based on the cost-effectiveness of the undergrounding program, but ignore the cost-effectiveness of each circuit, particularly since these are severable projects.

The Company also says that it intends to scale up its undergrounding program, with the goal of converting 400 miles per year by 2028. While, at this time, the Company's goals remain aspirational,[23] witness Bunch and others raised legitimate concerns regarding the Company's stated reasons for this "scale up." According to the Company, the Commission should approve more undergrounding projects to "better align [it] with the Company's peers, who have larger

[22] Figure 3, above, illustrates the point. By using a programmatic BCA, the Company can hide less cost-effective undergrounding projects in a program that is skewed by of a few extremely cost-effective projects.

[23] Kelly Rebuttal, 3 Tr 1601 ("It is also important to note that the Company is not proposing to immediately scale from 8.8 miles of OHUG work to 400 miles in this proceeding.").

percentages of their distribution systems underground."[24] The Company estimates that it needs to convert a "minimum of 2,000 to 9,950 additional miles" to be competitive with other, similarly situated utilities.[25] However, there is no precedent that suggests that it would be reasonable or prudent to approve expensive new capital projects just because other utilities have been approved for similar projects.

c. The Company failed to offer a legitimate critique of CUB witness Bunch's analysis.

Company witness Kelly rebuts witness Bunch's analysis of the undergrounding program and offers two reasons that it is incomplete.[26] Kelly's arguments are not persuasive. First, Kelly claims that Bunch "does not take into consideration the costs of alternatives," like continued vegetation management.[27] This alleged omission was not in error, however. Bunch's position on undergrounding in this case is that the Company should have produced individual, project-specific BCAs and compared undergrounding projects against one another to evaluate their cost effectiveness. A programmatic BCA—considering such alternatives as "Aerial Spacer Cable including Forestry" or "Tree Wire including Forestry"—would provide little value in comparing the cost effectiveness of one undergrounding project against another and prioritizing investments in the most cost-effective projects.

Second, Kelly contends that Bunch's model is incomplete because it is solely based on the present value of avoided interruption costs and "ignores many of the [other] costs included in a

[24] Kelly Direct, 3 Tr 1439.

[25] Kelly Direct, 3 Tr 1440.

[26] Kelly Rebuttal, 3 Tr 1615.

[27] Kelly Rebuttal, 3 Tr 1615-16.

BCA."[28] While it is true that Bunch did not include those costs in his calculations, the effect is inconsequential. The key figure in Bunch's analysis is the present value of undergrounding reliability, and accepting Kelly's suggestions would further reduce the expected value of the undergrounding program.

d. MNSC recommends a reduction in scale of the Company's test year undergrounding program, as the Commission ordered in the last rate case.

In Case No. U-21585, the Commission rejected Consumers' multi-million-dollar proposal for a new undergrounding pilot program because it was "premature" and not sufficiently supported by evidence.[29] Again, the Company makes a multi-million-dollar proposal for a new undergrounding pilot program in this case, and again, the Company's proposal includes insufficient evidence to fully consider the cost effectiveness of individual undergrounding projects. Based on CUB witness Bunch's own analysis (discussed above), only a fraction of the Company's proposed projects are sufficiently high impact to justify the extremely high cost of undergrounding. According to witness Bunch, these high-impact projects represent just 11.3 miles out of Consumers' proposed 50 miles.[30] Bunch recommends that the Commission only approve spending on those 11.3 miles of high-impact projects, which are identified by name in Bunch's Table 9, below.[31]

[28] Kelly Rebuttal, 3 Tr 1615-16 (claiming Bunch ignores relevant costs included in a BCA, "such as Return on Equity, interest, depreciation, taxes, and O&M that customers will pay in return for the improved reliability benefits").

[29] See Case No. U-21585, Order, March 21, 2025, p 80.

[30] Bunch Direct, 6 Tr 4064.

[31] *Id*. at 52 (recommending the Commission disallow spending on all other proposed undergrounding projects).

Table 9. MNSC Proposed Undergrounding Projects.[32]

Line Number	Project Description	Miles
8	LAKE LEANN/LAKE LEANN/282	1.0
10	PECK ROAD/M-91/473	2.1
11	PENINSULA/MAPLETON/124	1.1
12	SPRUCE ROAD/EAST BAY/693	0.5
13	SPRUCE ROAD/EAST BAY/868	0.7
16	BLACKMAN/SANDSTONE/404	2.7
17	KOLASSA/MATTESON/187	0.8
18	TRUFANT/GOWEN/847	1.1
22	WHITTEMORE/SAND LAKE/28	0.9
28	BROOKLYN/BROOKLYN/811	0.4

The Commission should adopt Bunch's recommendation, which will serve customer interests in improving LVD resiliency while simultaneously saving ratepayers $15,480,000 relative to the Company's proposal.

B. Generation Capital Expenditures -- The Commission should disallow inclusion in rate base of capital expenditures for two projects at the Jackson gas plant, totaling $5.28 million in expenditures, because Consumers provided insufficient support that the projects have positive economic benefits.

MNSC believe the following portions of the record are relevant to this issue: Direct Testimony of Consumers Energy witness Richard Blumenstock, 6 Tr 3539-40; Blumenstock Revised Rebuttal, 6 Tr 3616-22; Exhibits A-42 and A-45; Direct Testimony of MEC-CUB witness Tyler Comings, 6 Tr 3880-01 (public) and 6 Tr 4625-4646 (confidential); and Exhibits MEC-4 through MEC-14C.

In his direct testimony, MEC-CUB witness Tyler Comings recommended that the Commission deny Consumers approval to include in rate base the cost of two capital expenditures at the Jackson gas plant because the Company did not demonstrate that the projects have positive economic benefits. For each project, Consumers used inaccurate assumptions in the analysis used

[32] Bunch Direct, 6 Tr 4065 (citing Company Ex A-167 (JMP-2), p 21).

to support the economic benefit of the project. Consumers conceded that witness Comings was correct about the inaccurate assumptions. The Company attempted to introduce new analyses of the two projects on rebuttal, but the testimony and exhibits regarding the new analyses were stricken. The Commission should therefore adopt the two disallowances.

Witness Comings explained that Consumers has three natural gas combined cycle (NGCC) plants: Jackson, Covert, and Zeeland.[33] The Jackson plant is the least efficient and most expensive of the three NGCC plants to operate.[34] Consumers overstated the recent historic net energy value (NEV) – the assessment of costs versus revenues – of the Jackson plant by presenting lower variable operating costs than it has actually incurred in recent years.[35] Going forward, the economics of gas plants have significant upside risk due to upward macroeconomic pressures on natural gas prices.[36] Because it has a higher heat rate (is less efficient) than the other gas plants, the Jackson plant is more vulnerable to those risks.[37]

To support spending on its gas plant projects, Consumers conducted an economic assessment that compared the benefits of the project expressed as an estimate of the value of energy and capacity that could be lost to extended outage or derate if the project was *not* done with the costs of doing the project.[38] If the discounted benefits of the project outweighed the discounted costs, then the project was found to be beneficial.[39]

---

[33] Comings Direct, 6 Tr 3884.

[34] *Id*.

[35] *Id*. at 3886-87 (public) and 4631-32 (confidential).

[36] *Id*. at 3890-91

[37] *Id*. at 3890-91.

[38] *Id*. at 3893.

[39] *Id*.

The first project for which Mr. Comings recommended a disallowance is the JGS Generator Step Up (GSU) Transformer Site Spare project, Project ID 13478. Consumers projects $1.33 million of spending on the GSU spare transformer project in the bridge period and $2.33 million in the projected test period, for a total of $3.66 million.[40] Mr. Comings sponsored the Company's concept approval for the project as Exhibit MEC-11C.[41] Consumers proposed the GSU spare transformer project to replace this spare part to avoid "significant loss of power generation, ranging from 47 MW to 104 MW."[42] The Company claims that the lead time to get the part is three years, although the rest of the 531 MW plant would still be available in the event of the part's failure.[43] Consumers evaluated the project compared to two alternatives: (1) "do nothing", where it assumed there would be a failure leading to a derate of 104 MW, and as a result lose capacity value and net energy value from not producing energy from those 104 MWs for three years; and (2) leasing a transformer while repairing the failed one, which would include a 90-day outage.[44]

Witness Comings testified that Consumers evaluated the energy value of the GSU transformer project using the Aurora computer model, but the Company used inaccurate assumptions about the capacity factor of the Jackson plant and the probability of failure of the existing equipment in its analysis – both of which skewed the results to overstate the benefit-cost ratio of the project.1F[45] C Comings explained that the analysis assumed the Jackson plant would normally operate at between 65 and 84 percent capacity factor, but in the last five years it has

[40] *Id*. at 3895.

[41] Ex MEC-11C, Company Response U21870-MNSC-CE-0071_ATT_0003 CONF.

[42] Ex A-45, p 1.

[43] Comings Direct, 6 Tr 3896.

[44] *Id*.

[45] *Id*. at 3896-97 (public) and 4642 (confidential).

operated between 31 and 39 percent capacity factor.[46] Comings also explained that Consumers estimates there is only a 5 percent chance of failure of the GSU spare transformer that would lead to the loss of power, and that this probability would increase by 5 percentage points each year.27F[47] However, Consumers did not include that probability in its analysis, but rather assumed that failure was 100 percent certain without the project.[48] Finally, Comings explained that Consumers used the maximum de-rate of 104 MW in its analysis, rather than a range between 47 MW and 104 MW.[49] These three assumptions all lead to a substantial overstatement of the project's energy value.

On rebuttal, Mr. Blumenstock agreed with Mr. Comings about both the capacity factor assumption and the treatment of probability of failure in the evaluation of the GSU Transformer project.2F [50] He disagreed that a 47 MW de-rate is physically possible,[51] but the rest of his rebuttal about the capacity factor and probability of failure assumptions was stricken.[52]

Mr. Blumenstock also disputed Mr. Comings' proposed disallowance amount of $3.67 million, asserting that the Commission approved $916,667 of the total project cost in Case No. U-21585, and therefore the maximum disallowance should be limited to the incremental amount of $2.75 million.[53] However, that is not what the Company's Part III filing attachment 133, admitted

[46] *Id*. and Ex MEC-11, disc resp MNSC-CE-0071_ATT_0003 CONF. These figures are redacted in Mr. Comings' testimony because their source is a confidential discovery response. However, Mr. Blumenstock did not redact them in his rebuttal, so they are not redacted in this brief.

[47] Ex A-45, p 1; Comings Direct, 6 Tr 3897 (public) and 4642 (confidential).

[48] Comings Direct, 6 Tr 3897 (public) and 4642 (confidential).

[49] Comings Direct, 6 Tr 3897 (public) and 4642 (confidential).

[50] Blumenstock Rebuttal, 6 Tr 3617.

[51] *Id*. at 3618.

[52] Ruling on Motion to Strike, November 7, 2025.

[53] *Id*. at 3619.

as Ex MEC-50, says. Line 20 of that attachment presents the spending information for the Jackson plant GSU spare transformer project. Line 20 does identify a total amount approved in the Commission Order in U-21585 of $916,667. However, it also identifies total requested capital expenditures in this rate case of $3,666,667 – which rounds to the amount recommended for disallowance by Mr. Comings. And line 20 of attachment 133 identifies total project expenditures for the GSU project of $4,583,334. That figure is the sum of the $916,667 approved in U-21585 and the $3,666,667 proposed for approval in this case. Therefore, Mr. Blumenstock is wrong when he says that the $916,667 should be removed from the $3,666,667 disallowance that Mr. Comings recommends. The $3,667,667 does not include the $916,667 – attachment 133 confirms that the $3,667,667 is the incremental spending sought for approval in this case.

The second project for which Mr. Comings recommended a disallowance is the Jackson Plant LM1-6 variable inlet guide vane (VIGV), Project ID 13475. Consumers projects $7,885 of spending on the VIGV project in the historic test period, $646,911 in the bridge period, and $960,102 in the projected test year, for a total of $1.61 million.[54] Mr. Comings sponsored the Company's concept approval for the project as Exhibit MEC-12.[55]

The VIGV project involves installing equipment to increase the plant's efficiency and improve performance.28F[56] Consumers' support for the project relies on estimates of avoided repair costs as well as fuel savings and increased energy value from the assumed efficiency gain.[57] Mr. Comings testified that Consumers also used the Aurora model to estimate the value of the

[54] *Id*. at 3895.

[55] Ex MEC-12, discovery response MNSC-CE-0072_ATT_0004.

[56] Coming Direct, 6 Tr 3899; Ex MEC-12, MNSC-CE-0072_ATT_0004.

[57] *Id*.

project – but would not produce any calculations or other analytical support for that evaluation.8F[58]

On rebuttal, Mr. Blumenstock conceded that the company used an inaccurate capacity factor to model the VIGV project, too.9F[59] Most of his rebuttal regarding the VIGV project was also stricken.[60]

Mr. Blumenstock again disputed Mr. Comings' proposed disallowance amount of $1.61 million, asserting that the Commission approved $1,036,667 of the total project cost in Case No. U-21585, and therefore the maximum disallowance should be limited to the incremental amount of $578,031 million.[61] However, like the GSU project, attachment 133 proves that Mr. Blumenstock is wrong about the VIGV disallowance too.[62] Line 24 of that attachment presents the spending information for the Jackson plant VIGV project. Line 24 does identify a total amount approved in the Commission Order in U-21585 of $1,036,667. However, it also identifies total requested capital expenditures in this rate case of $1,614,898 – which rounds to the amount recommended for disallowance by Mr. Comings. And line 20 of attachment 133 identifies total project expenditures for the VIGV project of $2,643,680. That figure is the sum of the $1,036,667 approved in U-21585 and the $1,614,898 proposed for approval in this case. Therefore, Mr. Blumenstock is wrong when he says that the $1,036,667 should be removed from the $1,614,898 disallowance that Mr. Comings recommends. The $1,614,898 does not include the $1,036,667 –

[58] Comings Direct, p 20 and Ex MEC-12, MNSC-CE-0072_ATT_0004, p 7.

[59] Blumenstock Rebuttal, 6 Tr 3617 and 3620.

[60] Ruling on Motion to Strike, November 7, 2025.

[61] Blumenstock Rebuttal, 6 Tr 3620.

[62] Ex MEC-50, CECo Part III Filing Requirements Att 133.

attachment 133 confirms that the $1,614,898 is the incremental spending sought for approval in this case.

Lastly, Mr. Blumenstock opined that Mr. Comings "seems to focus on the economics of the Jackson Generating Station as compared to the Company's other gas generating sites, Covert and Zeeland;" and that "[t]he electric rate case is not the proper venue to make decisions about the future of generating assets" – but, rather, the next IRP is.[63] However, Mr. Comings specifically testified that he is not recommending that the Jackson plant be retired earlier than its current planned retirement date of 2040 – rather, he said he is "flagging that the Jackson plant is the most economically vulnerable of the three NGCC plants, and thus further investment in the plant should be carefully considered."[64]

In sum, the Commission should disallow inclusion in rate base of $5.28 million in capital expenditures for the Jackson plant GSU spare transformer and VGIV projects because Consumers conceded errors in the analyses supporting the projects and Mr. Comings correctly presented the incremental spending sought for the two projects in this case. The Company is free to return in the next case and present more accurate analyses to seek approval of expenditures as historic spending.

C. Fleet Capital Expenditures -- The Commission should direct the Company to revise its internal fleet electrification target so that all light-duty vehicle replacements are electric by 2030.

MNSC believe the following is the record on this issue: Direct Testimony of Company witness Quentin A. Guinn, 3 Tr 540-622, and his sponsored exhibits A-12, Schedule B-5.6 (QAG-1) and A-101 (QAG-2) to A-106 (QAG-7); Rebuttal Testimony of Company witness Quentin A. Guinn, 3 Tr 628-29; Cross Examination of Company witness Quentin A. Guinn, 3 Tr 630-34; Direct Testimony of Staff witness Allan D. Freeman, 6 Tr 4246-56; Direct Testimony of Douglas B. Jester, 6 Tr 3997-99, and his sponsored exhibit CUB-18; and Ex MEC-40.

[63] Blumenstock Rebuttal, 6 Tr 3622.

[64] Comings Direct, 6 Tr 3891.

The Company's proposed 30 percent fleet electrification target lacks an analytical foundation and falls short of what is reasonable and achievable. As MNSC witness Mr. Jester explained, the target "was set as a starting point and was not the product of detailed analysis."[65] Rather than evaluating what level of electrification was feasible, the Company simply conducted an assessment "structured around the 30% goal."[66] This backwards approach—fixing a low target first and then evaluating electrification of the fleet only within that constraint—does not reflect the level of fleet electrification that is reasonably attainable or provide a rational basis for accepting the Company's proposed target.

A significantly higher level of fleet electrification is practicable for the Company. As Mr. Jester testified, utilities have a "uniquely low-friction opportunity" to electrify their vehicles because they own and operate the very grid infrastructure required to support fleet charging.[67] Unlike most fleet operators, the Company does not need to depend on third parties for fueling or for the installation of charging equipment.[68] This structural advantage eliminates many of the barriers that constrain private-sector or municipal fleets and makes a more ambitious target both reasonable and achievable.[69]

Moreover, light-duty vehicles constitute the bulk of the Company's fleet, and "can be electrified readily with models that are already commercially available today."[70] While certain specialized equipment may not yet be easily electrifiable, these limited exceptions do not justify

[65] Direct Testimony of Douglas B. Jester, 6 Tr 3997.

[66] *Id.* at 3998.

[67] *Id.*

[68] *Id.*

[69] *Id.*

[70] *Id.*

the Company's failure to adopt a more ambitious target, let alone its plan to retreat from its modest 30 percent target. As shown in Exhibit CUB-18, the Company is "reevaluating" and likely stepping back from its current 30 percent target,[71] even though "commercially available models exist for most of the vehicle and vehicle types in the Company's fleet, including those that comprise the majority of its vehicles."[72]

Given the availability of suitable EV models today and the Company's unique control over charging infrastructure, Mr. Jester recommends—and the Commission should require—that the Company revise its fleet electrification target so that all light-duty vehicle replacements are fulfilled with electric models no later than 2030.[73] This recommendation aligns fleet turnover with normal replacement cycles, ensures that the Company leads by example on transportation electrification, and enables customers to benefit from the lower maintenance and fueling costs associated with EVs.[74]

The Company's opposition to Mr. Jester's recommendation, reflected in the rebuttal testimony and discovery responses of witness Guinn,[75] lacks merit. At hearing, Mr. Guinn acknowledged that his critique rested on the incorrect assumption that Mr. Jester had proposed replacing the Company's entire 900-vehicle light-duty fleet with EVs by 2030 regardless of whether vehicles were due for replacement.[76] In fact, as Mr. Guinn conceded, Mr. Jester recommends that by 2030 all *necessary* replacements of light-duty vehicles should be fulfilled

[71] Ex CUB-18, Consumers Energy's Answer to MNSC-CE-0582, p 1.

[72] Jester Direct, 6 Tr 3998.

[73] *Id.* at 3998.

[74] *Id.*

[75] *See* Rebuttal Testimony of Quentin A. Guinn, 3 Tr 628-29; Ex MEC-40, Company response to discovery request U21870-MNSC-CE-0803.

[76] Cross Examination of Quentin A. Guinn, 3 Tr 630-34.

using electric models.[77] To his credit, Mr. Guinn committed that the Company would assess the feasibility of implementing Mr. Jester's recommendation.[78] In parallel, the Commission should direct the Company to adopt a target of fulfilling all light-duty vehicle replacements with electric models by 2030.

D. Transportation Electrification Plan Expenditures -- The Commission should approve Consumers Energy's Transportation Electrification Plan proposals with targeted modifications.

MNSC believe the following is the record on this issue: Revised Direct Testimony of Company witness Jeffrey A. Myrom, 3 Tr 1858-75, and his sponsored exhibits A-12, Schedule B-5.8 (JAM-1), A-164 (JAM-2), and A-165 (JAM-3); Rebuttal Testimony of Company witness Jeffrey A. Myrom, 3 Tr 1876-85, and his sponsored exhibits A-223 (JAM-4) and A-224 (JAM-5); Direct Testimony of Staff witness Allan D. Freeman, 6 Tr 4246-56; Direct Testimony of Staff witness Kevin Krause, 6 Tr 4501-06; Direct Testimony of Douglas B. Jester, 6 Tr 3997-99, and his sponsored exhibits CUB-11 to CUB-20; Direct Testimony of MEIU witness Sophia Schuster, 6 Tr 4122-74, and her sponsored exhibits MEIU-1.1 to MEIU-1.4; Rebuttal Testimony of MEIU witness Sophia Schuster, 6 Tr 4175-91; and Direct Testimony of METC witness Michael Fleck, 4 Tr 3183-93.

MNSC strongly support the Company's Transportation Electrification Plan ("TEP") and its goal of enabling one million EVs in its service territory by 2030.[79] At the same time, more action is needed for the TEP to address key barriers to EV adoption, to align with the Company's goals and state policy objectives outlined in the MI Future Mobility Plan and the MI Healthy Climate Plan, and to maximize the benefits of EV charging load to the grid and to all ratepayers.

In this case, Consumers Energy proposes two enhancements to the TEP: (1) expanded outlet eligibility for rebates, which MNSC supports; and (2) continuation of the current terms for

[77] *Id.*; see also Jester Direct, 6 Tr 3998 ("The Company should revise its target so that all light-duty vehicle replacements are 21 fulfilled by electric vehicles no later than 2030.").

[78] *Id.* at 3 Tr 633.

[79] *See* Case No. U-21538, Consumers Energy, Consumers Energy Company's Transportation Electrification Plan 2024, available at: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000EFQgtAAH.

DC fast-charging rebates, which MNSC recommends modifying in light of the changed federal policy landscape. Specifically, MNSC recommends that the Company revise its fast-charging rebate structure to allow applicants to request variable rebate amounts and extend rebate availability for seven years rather than two—aligning the program with the original timeline of the federal 30C Alternative Fuel Vehicle Refueling Property Credit, which will now sunset in 2026 under the One Big Beautiful Bill Act ("OBBBA") rather than 2032.

In addition, MNSC recommend that the Commission direct the Company to take the following steps to enhance its TEP consistent with Commission guidance and state goals:

- develop a proposal in its next rate case to allocate specific funding for targeted education and outreach to multifamily dwellings;
- develop a proposal in its next rate case to pilot active managed charging and telematics within the PowerMIDrive program;
- reintroduce, in its next rate case or earlier if practicable, its previous proposal to pilot rebates for battery-integrated DC fast-charging sites; and
- develop a proposal in its next rate case to expand PowerMIFleet with a V2G-enabled electric school bus pilot.

1. The Commission should extend the fast-charging rebates through 2032 and revise the program to allow variable rebate levels.

MNSC supports continuation of the Company's DC fast charging ("DCFC") rebate program but recommends targeted modifications to ensure the program remains effective in the current funding landscape. As Mr. Jester explains, the elimination of the federal 30C Alternative Fuel Vehicle Refueling Property Credit has removed a significant source of outside support for fast-charging development.[80] In the absence of that credit, which will now sunset in 2026 rather than 2032, many site hosts will require higher levels of assistance to move projects forward.[81] The

[80] Jester Direct, 6 Tr 4002-03.

[81] *Id.*

Commission should therefore direct the Company to revise its application process to allow applicants to request higher project-specific rebate amounts, justified by their individual circumstances.[82] The Company would retain discretion to select the most competitive applications, with competitiveness would be assessed in part based on the rebate amount requested.[83] This approach ensures that ratepayer funds are allocated efficiently and effectively.

MNSC further recommends extending the availability of DCFC rebates for a longer and more predictable period to provide the stability necessary for continued progress toward a reliable statewide fast-charging network. Mr. Jester recommends that rebates remain available for seven years, consistent with the original planned duration of the 30C tax credit.[84] At a minimum, the DCFC rebates should remain available through 2030, the period covered by the Company's TEP. This recommendation aligns with the approach proposed by DTE in its current electric rate case and is supported by numerous parties, including Staff, who explained that avoiding a disruptive "interruption in availability and issuance of [rebates]" is necessary to prevent undermining state policy objectives.[85] Staff has indicated that it would not oppose an extension of DCFC rebates through 2030 in this proceeding.[86]

Accordingly, MNSC urge the Commission should approve continuation of the DCFC rebate program with the following modifications (1) adoption of a flexible, applicant-driven rebate-request process to ensure effective use of incentives, and (2) extension of rebate availability through at least 2030 to maintain stable support for fast-charging deployment.

---

[82] *Id.*

[83] *Id.*

[84] *Id.*

[85] Case No. U-21860, Rebuttal Testimony of Allan D. Freeman, 5 Tr 5206.

[86] Ex MEC-49, MPSC Staff's Answer to MNSC 1st DRs 1-2, p 1.

2. The Commission should direct Consumers Energy to develop a targeted outreach program to support multifamily dwelling participation in PowerMIDrive.

Under the PowerMIDrive Program, rebates for multifamily dwelling charging make up just 12% of total non-residential rebates—less than any other category, including DCFC, overnight destination, public, and community charging.[87] Residential rebates—which, like multifamily rebates, support access to home charging that is essential for EV adoption—outpace multifamily rebate uptake by roughly 90 to 1.[88] As Mr. Jester testifies, the "relatively small number of multifamily rebates issued to date is concerning, given the importance of this customer segment for equitable access to EV charging."[89] Multifamily properties face well-documented barriers, such as shared parking arrangements and complex landlord–tenant cost allocation, that likely require more focused attention than they have received to date, particularly given current levels of program participation.[90]

The Company's proposal to expand outlet eligibility to better attract multifamily site hosts is a step in the right direction. However, to meaningfully expand access in this critical market segment, Mr. Jester recommends that the Company dedicate resources to targeted outreach and education specifically aimed at multifamily property owners and managers.[91] Strengthening

[87] Jester Direct, 6 Tr 4003 (tabulating data from Ex CUB-13, Consumers Energy's Answer to MNSC-CE-0569 and Ex CUB-16, Consumers Energy's Answer to MNSC-CE-0583.

[88] *Id.*

[89] *Id.*

[90] *Id.*

[91] *Id.* at 6 Tr 4004.

outreach efforts will help overcome structural barriers to deploying EV charging at multifamily dwellings and ensure that the program delivers on the Company's goal of equitable access to EV charging.

3. The Commission should require Consumers Energy to propose three EV load-management and grid-support pilots in its next rate-case.

The Company's TEP relies almost entirely on passive strategies to influence EV charging behavior and manage EV charging load. As Mr. Jester explains, the Company's reported success in shifting "the vast majority of L1 and L2 charging to off-peak hours is achieved primarily through time-of-use rates, customer education, and incentive payments."[92] Many customers first engage with these programs through charger rebates, such as the PowerMIDrive program, which "uses AMI data to verify charging patterns and provides participating customers with monthly incentives to avoid on-peak charging."[93] Critically, however, the Company "does not employ active managed charging, telematics-based control, or [vehicle-to-everything] strategies to directly modulate charging load,"[94] and reports only that it is "monitoring developments to see how these technologies mature" and "presently has no plans" to develop such capabilities.[95]

Given expected EV-load growth and the limitations of the Company's current approaches to manage charging load, the Commission should require the Company to propose a set of pilots that begin integrating more active load-management tools into its TEP. Specifically, the Company should develop (1) an active managed charging and telematics pilot within PowerMIDrive; (2) a vehicle-to-grid ("V2G") enabled electric school bus pilot within PowerMIFleet; and (3) rebates

[92] *Id.*

[93] *Id.*

[94] *Id.*

[95] Ex CUB-14, Consumers Energy's Answer to MNSC-CE-0576.

for battery-integrated DC fast charging sites. Such direction is consistent with the Commission's recently adopted filing requirements for TEPs, which provide that utilities "must seek to maximize the overall benefits of EVs" and must address "opportunities for efficient grid management" and "how transportation electrification can support the efficient integration of renewables."[96]

a. The Commission should direct the Company to propose an active managed charging and telematics pilot within PowerMIDrive.

Mr. Jester's testimony establishes that active managed charging must be pursued now, not in a future TEP cycle.[97] The Company itself acknowledges that "without EV load-management programs, most customers will pay no attention to on-peak time periods…when charging."[98] While the passive strategies used to date have shifted most Level 1 and Level 2 charging off-peak, these results reflect a "self-selecting group of early adopters who are willing to engage with their utility and manage charging," not the behavior of the broader EV-driving population.[99]

Moreover, the Company's own forecasts show that "overall EV load growth is expected to outpace the growth of TEP-managed EV load between now and 2030."[100] This imbalance raises two concerns: (1) unmanaged load growth may soon overwhelm the benefits of the current passive managed-charging strategy, underscoring the need to scale program enrollment; and (2) "the average future EV driver cannot be assumed to behave like the early adopters who have participated to date," meaning incentives and education alone will not be sufficient at scale.[101]

---

[96] Case No. U-21492, Ruling, January 24, 2025, p 3.

[97] *See* Jester Direct, 6 Tr 4005.

[98] Case No. U-21538, Consumers Energy, Consumers Energy Company's Transportation Electrification Plan 2024, p 7, available at: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000EFQgtAAH.

[99] Jester Direct, 6 Tr 4005.

[100] *Id.* (citing Ex CUB-12, Analyzing TEP-Managed versus Overall EV Growth).

[101] *Id.*

For these reasons, Mr. Jester concludes that active managed-charging and vehicle-to-everything ("V2X") capabilities "should be integrated into the TEP now, rather than deferred until 2028," to ensure proven tools are in place before unmanaged load growth strains the distribution system. The Commission should therefore direct the Company to develop and file an active managed-charging and telematics-enabled pilot in its next rate case.

b. The Commission should direct the Company to propose a V2G-enabled electric school bus pilot within PowerMIFleet.

The Commission should require the Company to propose a pilot focused on electric school buses equipped with V2G capabilities. As Mr. Jester explains, school buses are an "especially promising application" for V2G because their daily operating schedules align well with grid needs—providing substantial availability for controlled charging and export—and because "their electrification produces significant public-health benefits by reducing students' exposure to diesel exhaust."[102]

A V2G-enabled school bus pilot would build naturally on the existing PowerMIFleet structure while demonstrating how fleets can provide both mobility and grid services.[103] This pilot would allow the Commission and stakeholders to evaluate the operational, grid, and customer-benefit outcomes of V2G in a real-world context.

c. The Commission should direct the Company to reintroduce its battery-integrated DC fast-charging pilot.

Finally, DC fast-charging presents distinct challenges that traditional load management strategies cannot address. As Mr. Jester testifies, "DCFC stations are not amenable to traditional

[102] *Id.* at 6 Tr 4007.

[103] *Id.*

managed-charging strategies. Drivers expect immediate, high-power charging and will not tolerate delays or curtailments."[104] Although the Company's prior battery-integrated DCFC proposal was not approved in Case No. U-21585, "the need for such solutions remains."[105]

Battery-integrated DCFC stations are commercially available today and are being deployed in other jurisdictions. As Mr. Jester explains, they "offer a practical way to buffer grid impacts, reduce interconnection costs, and improve reliability."[106] Because fast-charging growth will continue—and because unmanaged DCFC load poses significant localized grid challenges—the Company should revive its proposal, and the Commission should approve a battery-integrated DCFC pilot as part of this TEP to ensure that DCFC expansion is managed in a manner that protects both the grid and ratepayers.

III. CAPITAL STRUCTURE AND RATE OF RETURN

A. Capital Structure- The Commission should maintain a balanced capital structure for Consumers.

MNSC believes the following is the record on this issue: Direct Testimony of Company witness Marc R. Bleckman, 3 Tr 805-60, and his sponsored exhibits A-14, Schedules D-1 to D-6 (MRB-1 to MRB-7) and A-27 (MRB-8) to A-40 (MRB-21); Rebuttal Testimony of Company witness Marc R. Bleckman, 3 Tr 861-931, and his sponsored exhibits A-187 (MRB-22) to A-190 (MRB-25); Direct Testimony of Staff witness Kirk D. Megginson, 6 Tr 4519-57, and his sponsored exhibit S-4, schedules D-1 to D-6; Direct Testimony of CUB witness Matthew Bandyk, 6 Tr 3973-78, and his sponsored exhibit CUB-9; Direct Testimony of Attorney General witness Sebastian Coppola, 3 Tr 2514-33 (public), and 3 Tr 431-49 (public), and his sponsored exhibits AG-35 to AG-52; and Direct Testimony of ABATE witness Christopher C. Walters, 6 Tr 3766-67.

[104] *Id.* at 6 TR 4006.

[105] *Id.*

[106] *Id.*

Consumers' current authorized capital structure consists of 50% long-term debt and 50% common equity.[107] Consumers witness Marc Bleckman testified in support of the Company's proposed shift to 0.14% preferred stock, 49.11% long-term debt, and 50.75% common equity.[108]

CUB witness Bandyk recommended that the Commission maintain the current balanced capital structure,[109] as did Staff witness Megginson,[110] Attorney General witness Coppola,[111] and ABATE witness Walters.[112] Mr. Bandyk explained that determining the optimal capital structure involves weighing the relative risks of debt and equity. The risk of equity is generally higher because equity holders are lower in priority than debt holders when it comes to distributing a company's assets.[113] The cost of equity is generally higher than the cost of debt because of this increased risk and because interest payments on debt are generally tax deductible, which reduces its cost.[114] However, the risk of debt, which is the risk of being unable to repay it, increases as the amount of debt increases.[115] As the risk of debt increases, so does the cost to finance it.[116]

Mr. Bandyk calculated the interest coverage ratio for both a balanced capital structure and Consumers' proposed capital structure and concluded that Consumers could maintain less equity and more debt without materially increasing its financial risk.[117] As Mr. Bandyk explained, interest

---

[107] Bandyk Direct, 6 Tr 3973.

[108] *Id.*; Exhibit A-14, Sched. D-1 (MRB-1).

[109] Bandyk Direct, 6 Tr 3978.

[110] Megginson Direct, 6 Tr 4523.

[111] Coppola Public Direct, 3 Tr 2514.

[112] Walters Direct, 6 Tr 3746.

[113] Bandyk Direct, 6 Tr 3973-74.

[114] *Id.* at 3974.

[115] *Id.*

[116] *Id.*

[117] *Id.* at 3975-76.

coverage ratio is creditworthiness metric that shows a company's ability to pay interest on its debt, and it "implies a level of financial risk that implies what bond rating a company's debt is likely to receive at that ratio."[118] Mr. Bandyk used a table of ratios and their associated bond ratings published by Dr. Damodaran to estimate what Consumers' ratings would be for different combinations of capital structure and cost of equity. With the cost of equity at Mr. Bandyk's recommended 9.22% and a 50/50 debt-to-equity ratio, Consumers' interest coverage ratio would be 4.04, which lies in the range for A3/A- -rated debt.[119] "This result suggests that the Company could lower the equity share in its capital structure, and thus lower its cost of capital, without materially increasing financial risk."[120]

In rebuttal, Mr. Bleckman argued that the "actual interest coverage ratio ranges expected by the rating agencies for the Company's current credit rating are significantly higher than Mr. Bandyk calculates."[121] Mr. Bleckman cites a credit report from S&P indicating an expected range of 5.0 to 5.2 and a credit report from Moody's with an expected range of 5 to 6.[122] Both are higher than Mr. Bandyk's range of 3 to 4.2499, but nowhere does either agency state that a lower ratio would lead to a downgrade for the Company. They are simply ratios that the agencies expect the Company will achieve.

The Commission explained its approach to determining the appropriate capital structure in Consumers' most recent electric rate case:

---

[118] *Id.* at 3975.

[119] *Id.* at 3976.

[120] *Id.*

[121] Bleckman Rebuttal, 3 Tr 928.

[122] *Id.* (citing Ex A-36 (MRB-17), S&P August 2024 credit report, and Ex A-37 (MRB-18), Moody's August 2024 credit report).

> [T]he Commission must give consideration to both the utility's investors and its customers. In that regard, to determine an appropriate capital structure, the Commission must look to the evidence in each case and appropriately balance the interests of the utility's investors and the customers. The Commission has often found that this appropriate balance is a capital structure balanced between debt and equity.[123]

The Commission acknowledged that there is "some degree of flexibility" in how it applies its prior orders, and that "any target for the Company's capital structure should change if evolving circumstances indicate that the target is no longer a sound policy."[124] But the Commission found that Consumers "ha[d] not demonstrated significant changes in the economic circumstances to support a deviation from a balanced capital structure" and concluded 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*."[125]

Here again, Consumers has not demonstrated sufficient reason to deviate from a balanced capital structure. The Commission should adopt the recommendation of witnesses Bandyk, Coppola, Megginson, and Walters to maintain Consumers' authorized common equity ratio of 50.00%.

B. Return on Common Equity (ROE) – The Commission should reject Consumers' request for authorization to increase its current return on equity (ROE) to 10.25% and meaningfully decrease Consumers' authorized ROE to ensure the rates the Commission sets are just and reasonable.

MNSC believes the following is the record on this issue: Direct Testimony of Company witness Ann E. Bulkley, 4 Tr 2715-90, and her sponsored exhibit A-14, Schedule D-5; Rebuttal Testimony of Company witness Ann E. Bulkley, 4 Tr 2791-2916, and her sponsored exhibits A-206 (AEB-2) and A-207 (AEB-3); Direct Testimony of CUB witness Matthew J. Bandyk, 6 Tr 3939-3978, and

[123] Case No. U-21585, Order, March 21, 2025, p 232.

[124] *Id.*

[125] *Id.* at 232-33.

his sponsored exhibits CUB-1 through CUB-8 and CUB-10; Direct Testimony of Attorney General witness Sebastian Coppola, 3 Tr 2533-67 (public) and sponsored exhibits AG-35 to AG-52; Direct Testimony of Staff witness Kirk D. Megginson, 6 Tr 4519-57, and his sponsored exhibit S-4, schedules D-1 to D-6; Direct Testimony of ABATE witness Christopher C. Walters, 6 Tr 3742-3821, and his sponsored exhibits AB-5 to AB-19; Direct Testimony of Walmart witness Matthew T. Lyon, 3 Tr 2605-17 and his sponsored exhibits WAL-1 to WAL-4.

1. Introduction to ROE Section

Consumers witnesses Ann Bulkley testified in support of Consumers' request for authorization to increase its current 9.90% ROE, authorized in Case No. U-21585, to 10.25%. The Commission Staff, the Attorney General, ABATE, and CUB presented witnesses who testified in opposition to Consumers' request and submitted their own analyses and recommendations. Each recommended a decrease from the current authorized rate:

Party	**Witness**	**Recommended ROE**
Staff	Megginson	9.75%[126]
Attorney General	Coppola	9.80%[127]
ABATE	Walters	9.5%[128]
MNSC	Bandyk	9.22%[129]

Additionally, Walmart presented a witness addressing Consumers' proposed ROE without providing its own ROE analyses.

MNSC asks that the Commission consider the testimony, reasoning, and analyses CUB witness Matthew Bandyk presented supporting his recommended 9.22% ROE. Recognizing that

[126] Direct Testimony of Kirk D. Megginson, 6 Tr 4523.

[127] Public Direct Testimony of Sebastian Coppola, 3 Tr 2534.

[128] Direct Testimony of Christopher C. Walters, 6 Tr 3747.

[129] Direct Testimony of Matthew J. Bandyk, 6 Tr 3945.

9.22% is at low end of the range the parties have presented in this case, MNSC maintains that Mr. Bandyk accurately analyzed Consumers' market-based cost of equity and provided compelling support for the Commission to exert more substantial downward pressure on Consumers' ROE.

Additionally, MNSC asks that the Commission give real weight to customers' affordability and reliability concerns when balancing customer and shareholder interests to determine Consumers' ROE. MNSC acknowledges that the Commission has invoked the principle of gradualism to limit reductions in ROE in past cases.[130] MNSC recognizes that discretionary application of gradualism principles may support continued application of otherwise unsupported or no longer acceptable rates, allocations, and other components of ratemaking, including ROE. However, given ever-growing increases in rate base and serious affordability concerns, MNSC urges the Commission to consider the impacts to ratepayers from maintaining unreasonably high ROE in the interest of gradualism.

2. An ROE of 9.22% would accurately reflect Consumers' market-based cost of equity and support just and reasonable rates.

CUB witness Bandyk testified in support of reducing the Company's authorized ROE to 9.22%. After reviewing the standards for setting a reasonable rate of return, Mr. Bandyk discussed evidence demonstrating that utility regulators tend to set ROEs above what an economist would find appropriate using accepted methods of estimating investor perceptions of risk – i.e., a "market-based ROE."[131] As Mr. Bandyk explained: "A higher return implies higher risk, so approving ROEs that are higher than market returns would imply that regulated utilities are riskier

[130] See, e.g., Case No. U-21291, Order dated November 7, 2024, pp 100, 107-108 (declining to adopt PFD's recommended ROE of 9.40% and authorizing ROE of 9.80%).

[131] Bandyk Direct, 6 Tr 3948.

investments than the market as a whole. But they are not."[132] In fact, investing in regulated utilities is generally less risky than investing in the market as a whole.[133]

But, as Mr. Bandyk observed, utilities have a resource advantage in pursuing their aims during the regulatory ROE-setting process, regardless of the merits of their arguments.[134] Mr. Bandyk opined that regulators tend to set ROEs higher than the commensurate level of risk for regulated utilities because they accept inflated estimates of market risk like those Consumers has presented in this case.[135]

Authorizing a utility ROE that exceeds the market-based ROE causes an unjust transfer of wealth from ratepayers to shareholders.[136] Just as an ROE that is too low causes utility investors to lose wealth relative to what they should earn under a market-based ROE, an ROE that is too high causes customers to lose wealth by paying rates higher than they should pay under a market-based ROE.

If the Commission were to approve Consumers' requested rate increase with no changes except to adopt Mr. Bandyk's recommended 9.22% ROE, Consumers' overall rate of return would be 5.89% and Consumers would collect approximately $904.70 million from customers.[137] If the Commission were to approve Consumers' requested rate increase with no changes, including authorizing the requested 10.25% ROE, Consumers' rate of return would be 6.35% and it would collect approximately $975.36 million – i.e., $71 million more per year than customers would pay

[132] *Id.* at 3950.

[133] *Id.*

[134] *Id.* at 3951.

[135] *Id.*

[136] Bandyk Direct, 6 Tr 3947.

[137] Bandyk Direct, 6 Tr 3953.

under Mr. Bandyk's recommended ROE, which more accurately reflects Consumers' market-based cost of equity.[138] This amount dwarfs the cumulative $152 million over 18 years that Consumers suggests ratepayers saved in reduced borrowing costs because of its credit rating, which amounts to just $8.4 million per year.[139]

Mr. Bandyk confirmed that Consumers' current and proposed ROE amounts are excessive using two widely accepted methods for estimating Consumers' market-based ROE – the Capital Asset Pricing Model (CAPM) and Discounted Cash Flow (DCF) methods. These are two of the four methods Ms. Bulkley used in developing Consumers' requested ROE. Mr. Bandyk did not use the other two methods Ms. Bulkley used – the Empirical Capital Asset Pricing Model (ECAPM) and Bond Yield Risk Premium (BYRP) methods, for reasons discussed below.

The average results of Mr. Bandyk's CAPM and DCF calculations and his resulting recommended ROE and alternative recommended ROE are summarized as follows:

Method	**Result**
CAPM	8.11%
DCF	8.96%
Average of CAPM and DCF results	8.53%
Average of Consumers' current 9.90% ROE and average of CAPM and DCF results	9.22%

While the average of Mr. Bandyk's model results indicates that Consumers' market-based ROE is 8.53%, Mr. Bandyk recognizes the need to change Consumers' authorized ROE

[138] *Id.* at 2954.

[139] Bleckman Direct, 3 Tr 823; Ex A-32 (MRB-13). Mr. Bleckman testified that the Company saved customers "$152 million annually," which appears to have been an error. The exhibit Mr. Bleckman cites, Ex A-32 (MRB-13), titled "*Cumulative* Annual Interest Savings" (emphasis added), clearly indicates that the Company saved $152 million in interest cumulatively from 2008 through 2024. The most the Company appears to have saved in any single year was $32 million in 2018.

gradually.[140] Therefore, Mr. Bandyk recommends a 9.22% ROE, which represents the average of his estimates of Consumers' 8.53% market-based ROE and Consumers' current 9.90% ROE.

a. Capital Asset Pricing Model (CAPM)

For his CAPM analysis, Mr. Bandyk conducted four calculations, two using an equity risk premium (ERP) of 5.00% and a risk-free rate of 4.76% from the financial firm Kroll and two using an ERP of 4.05% and a risk-free rate of 4.23% from New York University professor Aswath Damodaran.[141] For one calculation using the Kroll numbers and one using the Damodaran numbers, Mr. Bandyk used the Value Line beta of 0.92; for the remaining two calculations, he used the Bloomberg beta of 0.68. Mr. Bandyk's results ranged from 6.96% to 9.37% and averaged out to 8.11%.[142] Mr. Bandyk used the same basic formula as Ms. Bulkley, but his result differs from hers because he used different inputs for the ERP, risk-free rate, and betas.

The ERP represents the additional return an investor could expect to receive for investing in the stock market rather than risk-free investments; it is calculated by subtracting the risk-free rate from the estimated rate of return for investing in the stock market.[143] Mr. Bandyk developed his ERP input to avoid being overly reliant on historical data.[144] ERPs derived from historical data are heavily influenced by the subjective judgment of the individual selecting the historical time period and subject to survivorship bias, which tends to inflate the CAPM results.[145]

[140] *Id.* at 2956.

[141] Ex CUB-5, CAPM Analysis.

[142] *Id.*

[143] Bandyk Direct, 6 Tr 3957.

[144] *Id.* at 3957-58.

[145] *Id.*

Mr. Bandyk used one ERP that represents the average of five estimates of the U.S. ERP published by Dr. Damodaran, who recommends the use of an implied ERP method that is "market-driven and current" rather than dependent on historical data.[146] To avoid relying on a single source, Mr. Bandyk also used the recommended U.S. ERP from Kroll.[147]

The Damodaran ERP is calculated by taking the discounted cash flow (DCF) method Mr. Bandyk and others in this case use to estimate Consumers' ROE and applying it to the S&P 500 to determine the rate investors expect for investing in the stock market, then subtracting the risk-free rate.[148] Dr. Damodaran's approach involves the use of an expected growth rate, or *g*, for which he uses the average of two-year growth forecasts of the aggregate earnings of the S&P 500.[149]

Ms. Bulkley uses a similar but simpler approach where *g* is one of only two inputs to her formula, meaning the value she uses for *g* will significantly affect the result.[150] The value she uses for *g* is inflated, as she assumes cash flows will grow in the long term at a constant rate based on analyst expectations of the next five years.[151] Dr. Damodaran's *g* more reasonably assumes cash flows will grow for five years at an analyst forecasted rate, then settle at a more sustainable rate in the long term.[152]

For his beta inputs, Mr. Bandyk used Bloomberg and Value Line betas for the companies in Ms. Bulkley's original proxy group[153] with one modification. Both Bloomberg and Value Line

[146] *Id.* at 3958-60.

[147] *Id.* at 3960.

[148] *Id.* at 3958-60.

[149] *Id.* at 3960.

[150] *Id.* at 3961.

[151] *Id.*

[152] *Id.* at 3959.

[153] Ms. Bulkley updated her proxy group in rebuttal, as this brief will discuss below.

report adjusted rather than raw betas, using an adjustment called the "Blume adjustment" that is meant to correct for the tendency for betas to revert to the mean of 1.0 in the long run.[154] But that tendency, which results from efforts to keep the systematic risk of most companies close to that of the market as a whole, is less present in regulated utilities that are inoculated from systematic risk by their ability to recover costs through rates.[155] In fact, an analysis of monthly returns for 57 publicly-traded electric and gas utilities from 1962 to 2007 showed that their average and median betas declined rather than rising to 1.0.[156] Therefore, Mr. Bandyk found it inappropriate to apply the Blume adjustment to the betas of regulated utilities, and removed it and used raw betas.[157]

b. Discounted Cash Flow (DCF)

For his DCF analysis, Mr. Bandyk performed two calculations using the same formula as Ms. Bulkley with different inputs, which resulted in an average ROE of 8.96%.[158] *First*, for both calculations, Mr. Bandyk used a weighted growth rate estimate that was lower than the growth rate estimate Ms. Bulkley used.[159] Ms. Bulkley used only short-term rates, leading to a "wildly unrealistic outcome."[160] Mr. Bandyk explained: "A DCF growth rate input higher than the growth rate of the economy as a whole implies that, in the long run, the Company will grow larger than the entire U.S. economy. Such an outcome is impossible."[161]

---

[154] *Id.* at 3963.

[155] *Id.* at 3963-64.

[156] *Id.* at 3964-65.

[157] *Id.* at 3963.

[158] Exhibit CUB-7, DCF (with Earnings Growth Rates) and CUB-8, DCF (with Dividend Growth Rates); Bandyk Direct, 6 Tr 3955.

[159] *Id.* at 3967.

[160] Bandyk Direct, 6 Tr 3967.

[161] *Id.*

Mr. Bandyk calculated his growth rate estimates using a two-stage DCF model endorsed by FERC for calculating ROE under the Federal Power Act. The FERC model involves weighting the short-term growth rate at 80% and the long-term growth rate at 20%.[162] This methodology, unlike Ms. Bulkley's, "reflect[s] the fact that in the long-term Consumers Energy cannot grow larger than the domestic economy of which it is a part."[163] For one calculation's short-term growth rate, Mr. Bandyk used the same short-term earnings per share (EPS) growth rates of the original proxy group companies Ms. Bulkley used in her DCF calculation.[164] For the other calculation's short-term growth rate, Mr. Bandyk used the average of the Value Line forecasts for dividend per share (DPS) growth for those same companies.[165] For a long-term growth rate for both calculations, Mr. Bandyk used the nominal GDP growth rate from 2028 through 2035.[166]

Second, Mr. Bandyk used a shorter timeframe when averaging stock prices to calculate dividend yields. Ms. Bulkley used stock prices averaged over 30-, 90-, and 180-trading-day periods but Mr. Bandyk used a period of 30 days ending September 4, 2025, to ensure the stock prices were as close as possible to the current spot price when CUB filed his testimony on September 29, 2025.

c. Unused Methods

Mr. Bandyk did not use the ECAPM because, to his knowledge, the Commission has never recognized it as a valid methodology for estimating ROE and Staff has historically declined to use

[162] *Id.* at 3968.

[163] *Id.*

[164] *Id.* at 3967-68; Ex CUB-7, DCF (with Earnings Growth Rates); Ex A-14 (AEB-1), Schedule D-5, p 3.

[165] *Id.* at 3969; Ex CUB-8, DCF (with Dividend Growth Rates).

[166] Bandyk Direct, 6 Tr 3968-69.

it.[167] In Consumers' 2023 rate case, Case No. U-21389, the PFD considered Consumers' use of the ECAPM and noted that Consumers "ha[d] not identified an order wherein the Commission has recognized let alone adopted the use of the ECAPM model" and that the ALJ was unaware of one.[168] The PFD also noted that "FERC does not recognize the use of ECAPM, which it considers to be an 'obscure' and 'more controversial' variant of CAPM" and that "the Commission 'has consistently taken a traditional approach' to establishing ROE, focusing on the 'most commonly-used, fundamental approaches.'"[169] The PFD found that "Consumers' ECAPM estimates should not be considered" and the Commission did not disagree.[170]

Mr. Bandyk did not use the Bond Yield Plus Risk Premium (BYRP) method because it is heavily influenced by ROEs set by other regulators, which, as Mr. Bandyk has explained, are generally higher than they should be, thereby leading to an inflated result.[171] As FERC has explained regarding a similar Risk Premium method, "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."[172] FERC has also found the Risk Premium model to be "largely redundant with the CAPM."[173]

---

[167] *Id.* at 3966.

[168] Case No. U-21389, PFD, December 21, 2023, p 337.

[169] *Id.* at 337-338.

[170] *Id.* at 338; Case No. U-21389, Order, March 1, 2024, pp 129-142 (reviewing PFD's ROE analysis without mentioning its ECAPM finding).

[171] Bandyk Direct, 6 Tr 3970.

[172] FERC Opinion 569, 169 FERC 61129 (2019), para 343.

[173] *Id*. at para 341.

3. Consumers' rebuttal is weak and unpersuasive.

In rebuttal, Consumers witness Ann Bulkley testified that "[n]othing" in the testimony of the five Staff and intervenor ROE witnesses "has caused [her] to change [her] conclusions or recommendations."[174] Having updated her analyses to reflect market data current through September 30, 2025, Ms. Bulkley found that the results of her analyses had mostly increased somewhat and still supported her recommended ROE of 10.25%.[175]

a. Ms. Bulkley failed to rebut Mr. Bandyk's testimony that ROEs are too high.

Responding to Mr. Bandyk's testimony that regulators tend to set utility ROEs too high, Ms. Bulkley starts by putting words in Mr. Bandyk's mouth and using them to paint Mr. Bandyk as an outlier. She states that Mr. Bandyk "suggests that previously authorized ROEs should not be considered for purposes of establishing the ROE for the Company in this proceeding,"[176] then cites the testimony of Mr. Megginson, Mr. Coppola, and Mr. Walters to support her claim that Mr. Bandyk is "alone in his position."[177] But Mr. Bandyk said no such thing. In fact, Mr. Bandyk expressly considered Consumers' previously authorized ROE of 9.90% in recommending an ROE of 9.22%, which represents a more gradual reduction that the 8.53% average of his CAPM and DCF analyses would have. The Commission should disregard this apparent attempt to undermine Mr. Bandyk's credibility.

[174] Rebuttal testimony of Ann E. Bulkley, 4 Tr 2797.

[175] *Id.* at 2797-99.

[176] *Id.* at 2806.

[177] *Id.*

Next, Ms. Bulkley discusses her "fundamental disagreement"[178] with the premise that regulators tend to set utility ROEs too high. She agrees with Mr. Bandyk that "there is a distinction between the cost of equity and the ROE authorized by regulatory commissions in setting just and reasonable rates," that cost of equity "cannot be definitively determined" and "must be estimated," and that there is "significant disagreement" about how to estimate the cost of equity.[179] She claims, however, that Mr. Bandyk has "provided no evidence that supports his position" that regulators have been getting ROEs wrong. Mr. Bandyk, however, cited several sources in support of his testimony, which is itself evidence supporting his position. The fact that Ms. Bulkley finds fault with Mr. Bandyk's sources does not render them nonexistent. Moreover, the PFD in Consumers' 2023 electric rate case found Mr. Bandyk's position well-supported:

> Mr. Bandyk offered compelling evidence that the average ROEs for regulated electric and gas utilities awarded by public regulatory 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. 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." 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."
>
> This PFD agrees. Indeed, that regulated utilities are much less risky than other businesses is without question.[180]

[178] *Id.* at 2807.

[179] *Id.*

[180] Case No. U-21389, PFD, December 21, 2023, pp 357-58 (citations omitted).

In support of her claim, Ms. Bulkley selectively quotes a Minnesota Public Utilities Commission (PUC) decision in an attempt to provide an example of a regulator "disagree[ing] with Mr. Bandyk's notion that there is and has been a substantial difference between authorized ROEs and the cost of equity for utilities."[181] But an examination of the context for the phrase "the Commission does not share this concern" makes clear that the Minnesota PUC was not referring to "an underlying assumption that the cost of equity and the return on equity are distinct concepts in the sense that utility earnings exceed the cost of equity over time." Rather, in that particular case, the Commission did not share the concern that the utility's earnings estimates should be rejected as a predictor of long-term growth. Here (bolded) is the part of the quote Ms. Bulkley left out after triple-emphasizing the sentence, "The Commission does not share this concern," and making it appear that that sentence was part of the preceding paragraph:

> **The Commission concurs with the Administrative Law Judge that the Company's methodology is well supported by the record and provides a well-reasoned basis for setting the cost of equity.**
>
> The Department's recommended cost of equity of 9.30% is informed by an underlying assumption that the cost of equity and the return on equity are distinct concepts in the sense that utility earnings exceed the cost of equity over time. This understanding, according to the Department, undermines the reliability of earnings' estimates in predicting long-term growth and instead justifies the use of a multi-stage DCF analysis that uses GDP to forecast the long-term cost of equity.
>
> The Commission does not share this concern. **While general statements about GDP and earnings estimates may offer broad perspectives on their overall usefulness, the parties' positions reflect philosophical and methodological differences that are qualitative in nature. But the Department has not**

[181] Bulkley Rebuttal, 4 Tr 2808.

demonstrated inaccuracies in Minnesota Power's earnings estimates in this case to justify dismissing them from consideration.[182]

Next, Ms. Bulkley provides what she characterizes as "examples where capital attraction and willingness to invest have been hampered when a regulatory jurisdiction is perceived as not being credit supportive."[183] Nowhere in her four-page discussion, however, does she mention the fact that these examples involve decisions to set ROEs well below any recommended ROE at issue in this case. The Illinois "regulatory decisions in December 2023 for Ameren Illinois Co. and Commonwealth Edison Co."[184] set the ROE for ComEd at 8.905%[185] and the ROE for Ameren at 8.72%.[186] The "unreasonable, arbitrary decisions"[187] in Connecticut included one setting an ROE of 8.70% for Aquarion Water Company. [188] There is no reason to find that the market would react similarly to the Commission adopting any ROE within the much higher range of options (9.22% to 9.85%) recommended by the Staff and intervenor witnesses in this case. Moreover, ROE alone did not prompt the reactions Ms. Bulkley discussed. For example, as she explained regarding Connecticut's Eversource, "Driving the cut in utility investment is Eversource's view that utility regulators have been slow to approve the recovery of $635 million in storm costs incurred from 2018 through 2021, $400 million in uncollected bills from ratepayers, a rate reduction imposed on Aquarion Water in its most recent rate proceeding, and elimination of a program supporting electric

[182] Minnesota Public Utilities Commission, Docket No. E-015/GR-21-335, Findings of Fact, Conclusions, and Order, February 28, 2023, p 45 (emphasis added).

[183] Bulkley Rebuttal, 4 Tr 2809.

[184] *Id.*

[185] Illinois Commerce Commission v Commonwealth Edison Company, Case No. 22-0486, Order, December 14, 2023, pp 320, 470.

[186] Illinois Commerce Commission v Ameren Illinois Company, Case No. 22-0487, Order, December 14, 2023, pp 222, 372.

[187] Bulkley Rebuttal, 4 Tr 2809 (internal quotation omitted).

[188] Connecticut Public Utilities Regulatory Authority Docket No. 22-07-01, Decision, March 15, 2023.

vehicles."[189] While ROE may have been a component of Eversource's difficulties, clearly other factors not applicable here played a significant role.

Next, Ms. Bulkley criticizes the sources Mr. Bandyk cited in support of his testimony that regulators tend to set ROEs too high. While each has limitations – for example, the Rode & Fischbeck study reviewed electric utility ROEs rather than gas utility ROEs and focused on the CAPM rather than other methods – all are credible, and all lend support for Mr. Bandyk's opinion. Ms. Bulkley also ignores that Mr. Bandyk cited the Rode & Fischbeck article specifically for the premise that the growing premium of awarded ROEs over the rate of return on long-term US Treasury bonds – a trend that Ms. Bulkley does not dispute – does not appear to be explained by "financial fundamentals" like changes in utilities' equity or debt risk.[190] While Ms. Bulkley highlights the article's caveat that the authors' research "does not *necessarily* imply that the rates of return authorized by regulators are too high, or otherwise *necessarily* inappropriate for utilities,"[191] she again ignores key context. As Mr. Bandyk noted, the authors stated that "absent some normative justification" for the growing premium of awarded ROEs over the rate of return on long-term US Treasury bonds, "it would appear that regulators are authorizing excessive returns on equity to utility investors and that these excess returns translate into tangible profits for utility firms."[192]

Ms. Bulkley also criticizes the Werner and Jarvis study Mr. Bandyk cites, but her criticisms do not hold water. First, she states that it "incorrectly assumes that a 1.00 percentage point change

[189] Bulkley Rebuttal, 4 Tr 2810.

[190] Bandyk Direct, 6 Tr 3948-50.

[191] Bulkley Rebuttal, 4 Tr 2813 (quoting David Rode and Paul Fischbeck, "Regulated equity returns: A puzzle," Energy Policy, October 2019) (emphasis added).

[192] Bandyk Direct, 6 Tr 3949, n 6.

in the yield on Treasury bonds will result in a 1.00 percentage point change in the authorized returns."[193] But the study does not contain this assumption. Next, she argues that the study's results are sensitive to the assumptions made by the CAPM and that this somehow invalidates the conclusion that authorized ROE is higher than the cost of equity.[194] But, under the two CAPM analyses the study used, ROE *was* found to be higher than the cost of equity. What remains uncertain is exactly by how much ROE is too high, not whether it is higher at all. Last, Ms. Bulkley argues that "it is not reasonable to conclude that the authorized ROEs in the US are too high based on a comparison to the returns authorized for utilities in the UK,"[195] but the comparison to UK returns is not critical to establishing the central and well supported claim that authorized ROEs are set above the cost of equity in the US.

Most importantly, Mr. Bandyk does not rely solely on evidence indicating that utility ROEs are too high generally to find that Consumers' requested ROE is too high in this case. While that evidence is reason to suspect the proposed ROE is too high, Mr. Bandyk confirms it by presenting his CAPM and DCF analyses.

b. ROE calculations

As previously noted, Ms. Bulkley finds no merit in any other witness's ROE analyses. After reviewing her particular criticisms of each, she "adjust[s]"[196] them all to reflect her preferred inputs and methods, which unsurprisingly inflates their results to align with her own.[197] The Commission

[193] Bulkley Rebuttal, 4 Tr 2814.

[194] Bulkley Rebuttal, 4 Tr 2814-15.

[195] Bulkley Rebuttal, 4 Tr 2815.

[196] Bulkley Rebuttal, 4 Tr 2871-2873; Ex A-206 (AEB-2), pp 25-49.

[197] *Id.*

should disregard this transparent attempt to conjure support for Consumers' excessive ROE request from witnesses who have opposed it.

i. Proxy Group

First, Ms. Bulkley criticized Mr. Bandyk's use of the proxy group she originally used. Noting that three companies in her original proxy group had been "involved in mergers and acquisition activity that was announced after the filing of [her] direct testimony" and therefore no longer met her screening criteria, she presented an updated analysis excluding those companies and stated that Mr. Bandyk should have excluded them, too.[198] But, while the results of her updated DCF analysis increased somewhat, her CAPM results were generally consistent with her original analysis, and no change was significant enough to prompt revision of her recommended 10.25% ROE.[199] Therefore, there is no reason to conclude that using her original proxy group rather than her revised proxy group would necessitate changes to Mr. Bandyk's recommendation.

ii. DCF

Regarding Mr. Bandyk's specific ROE calculations, Ms. Bulkley first takes aim at his use of a two-stage DCF model. First, she explains her belief that, because the utility industry is "mature" with "relatively stable demand," it is "more appropriate" to use the constant growth DCF model.[200] Then she argues that two-stage and multi-stage DCF models "introduce[] additional assumptions and potential analyst bias" because there are more variables involved: which model to use, which growth rates to use, how to weight the growth rates, and the duration of the stages in

[198] Bulkley Rebuttal, 4 Tr 2798-2780; 2824-25.

[199] *Id.* at 2799-80.

[200] Bulkley Direct, 4 Tr 2838.

a multi-stage DCF model.[201] But the constant growth DCF model is not a default – using the constant growth DCF model is itself a choice that can reflect analyst bias. And, once selected, the constant growth DCF model has fewer variables and is therefore more sensitive to any bias that may influence the selection of any one of them. The additional inputs, weighting, and blending in the two-stage and multi-stage DCF models, on the other hand, reduce the impact of any one variable.

Ms. Bulkley also challenges the premise that a company cannot out-grow the market over the long term, citing a 2012 study prepared for the Alberta Utilities Commission that purportedly showed total factor productivity (TFP) growth for US utilities (0.96%) exceeding TFP growth for the US economy (0.91%) from 1972 to 2009.[202] But even if TFP growth for US utilities exceeded TFP growth for the US economy from 1972 to 2009, it still does not follow that utilities can grow faster than the entire economy in perpetuity. First, 37 years is not in perpetuity. Second, it is reasonable to presume that, during that 37-year period, less productive utilities were acquired or replaced by more productive utilities. Therefore, industry-wide productivity growth from that period is skewed by survivorship bias – the less productive utilities do not show up in the growth figures to the same extent as more productive utilities do because the former exited the market.

Last, Ms. Bulkley disagrees with Mr. Bandyk's use of DPS growth rates for one of his two DCF calculations but does not address Mr. Bandyk's testimony regarding the advantages of using DPS growth rates. Specifically, Mr. Bandyk noted that some regulatory jurisdictions "have recognized that DPS growth rates carry the advantage that firms tend to keep their dividend growth stable over time, as opposed to EPS growth rates, which may vary based on firm-specific events

[201] *Id.* at 2839.

[202] Bulkley Rebuttal, 4 Tr 2842-43.

and economic conditions."[203] It was reasonable for Mr. Bandyk to consider both DPS and EPS growth rates in his DCF calculations.

iii. CAPM

Regarding Mr. Bandyk's CAPM analysis, Ms. Bulkley first takes issue with his use of Dr. Damodaran's risk-free rate, which was equal to the yield on 10-year U.S. Treasury bonds.[204] Ms. Bulkley argued that Mr. Bandyk should have used the 30-year Treasury yield because "utility companies represent long-duration investments."[205] But the rates the Commission will establish in this case are based on a single projected test year ending April 30, 2027, and, based on Consumers' history of applying for a rate increase each year, are not likely to last long past that date. Therefore, a shorter-term Treasury bond is appropriate, as it more closely matches the duration the rates set in this case will be in effect, while remaining sufficiently long-term to mitigate volatility.

Next, Ms. Bulkley disagrees with Mr. Bandyk's choice of market risk premia. She argues that Mr. Bandyk, along with every other Staff and intervenor witness in this proceeding, "develop[ed] their market risk premium independent from the risk-free rate . . . , which ignores the academic research that there is an inverse relationship between the risk-free rate and the market risk premium."[206] She suggests that, because Mr. Bandyk's risk-free rates (4.23% and 4.76) are "below or consistent with the long-term average risk-free rate,"[207] his market risk premia should

[203] Bandyk Direct, 6 Tr 3969.

[204] Bulkley Rebuttal, 4 Tr 2848.

[205] *Id.*

[206] Bulkley Rebuttal, 4 Tr 2849.

[207] *Id.* at 2857-58.

be higher than the long-term average market risk premium (7.31%).[208] Because Mr. Bandyk's ERPs (4.05% and 5.00%) are lower than 7.31%, Ms. Bulkley concludes that Mr. Bandyk's CAPM results must be too low.[209]

Ms. Bulkley's reliance on the 7.31% long-term historical average market risk premium is misplaced. As Mr. Bandyk explained in his direct testimony, two flaws render historical estimates essentially meaningless for purposes of a CAPM analysis. First, they are "extremely sensitive to the historical time period selected, meaning that the subjective judgment by the person deciding which time period to collect market data for has an outsized impact on the result."[210] Second, they are "subject to the problem of survivorship bias, where returns that go into historical ERPs tend to be those from stocks that remain in the market, rather than those that drop out."[211] The 7.31% historical average is inflated because it is missing returns from the large number of companies that dropped out of the market between 1926 and 2024.

Next, Ms. Bulkley argues that Mr. Bandyk's CAPM assumptions are inconsistent with his DCF results.[212] She finds it "counterintuitive" that the implied market return from four of the five estimates of the market risk premium Mr. Bandyk used to develop one of his CAPM inputs are lower than his DCF results because one would expect the return for the market to be higher than the return for the proxy group due to the lower beta for the proxy group companies.[213] But Ms. Bulkley is making an apples-to-oranges comparison by comparing market risk premia calculated

[208] *Id.*

[209] *Id.*

[210] Bandyk Direct, 6 Tr 3957-58.

[211] *Id.* at 3958.

[212] Bulkley Rebuttal 4, Tr 2860.

[213] *Id.*

by Dr. Damodaran using a DCF analysis for the S&P 500 to a DCF analysis for Consumers performed by Mr. Bandyk. Different results from different analyses performed by different analysts do not invalidate the results of either analysis. And the CAPM and the DCF typically yield different results, as demonstrated by the range of results presented by the ROE witnesses in this case, which is why analysts typically use more than one to estimate ROE. The fact that Mr. Bandyk's DCF result is higher than a CAPM input based on DCF results from another analyst demonstrates no fault with either analysis, only that they are different.

Last, Ms. Bulkley disagrees with Mr. Bandyk's use of raw betas.[214] She argues that the Blume adjustment "likely better reflect[s] the true beta of the utility sector inclusive of interest rate risk,"[215] but offers no support for this assumption, nor does she address Mr. Bandyk's explanation for why the Blume adjustment is inappropriate for regulated utility betas.

iv. Unused Methods

Regarding the ECAPM, Ms. Bulkley defends it as "consistent with academic literature" and points to two regulatory commissions that have accepted it.[216] She does not, however, contend with the fact that the MPSC has consistently declined to recognize it.

4. Conclusion to ROE Section

Consumers' proposed ROE is excessive and unsupported by the evidence. Every other party to analyze Consumers' market cost of equity has found that a reduction – not an increase – is warranted. The record also contains extensive evidence of serious customer concerns about affordability and reliability. The weight of the evidence in this case strongly supports a meaningful

[214] Bulkley Rebuttal, 4 Tr 2861-62.

[215] *Id.*

[216] Bulkley Rebuttal 4 Tr 2874, 2882.

reduction in Consumers' current ROE. For the reasons discussed above, the Commission should adopt Mr. Bandyk's recommended ROE of 9.22%.

IV. ADJUSTED NET OPERATING INCOME

A. Other O&M Expense -- Tree Trimming – The Commission should approve the Company's proposal to ramp up its LVD line clearing work to achieve a five-year cycle, with an additional portion of test-year spending recovered through securitization.

MNSC believe the following is the record on this issue: Revised Direct Testimony of Consumers witness Sara A. Stewart, 3 Tr 2185-2234, and her sponsored exhibits A-170 to A-177; Direct Testimony of Staff witness Jessica Duell, 6 Tr 4408-10; Revised Direct Testimony of MNSC witness Richard J. Bunch, 6 Tr 4046, 4051-53, and 4072; and Direct Testimony of MNSC witness Douglas B. Jester, 6 Tr 3989-91, 3997, and 4007.

MNSC does not dispute the Company's proposed changes to its line clearing program, which are generally consistent with the recommendations in the Liberty Audit.[217] Currently, Consumers is "working towards a seven-year effective clearing cycle" on its low voltage distribution (LVD) system.[218] The Company proposes further accelerating line clearing by ramping up to a five-year cycle.[219] The Company also proposes maintaining its current four-year cycle across its high-voltage distribution system.[220]

The Company seeks approval to increase operational spending by $72.7 million, which will facilitate Consumer's ramp-up of its line clearing work. MNSC raises no dispute about whether this spending should be approved, only how it should be accounted, which is addressed below in Section VII.D., "Securitization of Test Year Tree Trimming, LVD Pole Spending."

---

[217] Jester Direct, 6 Tr 3991.

[218] Bunch Revised Direct, 6 Tr 4051 (citing Stewart Direct, pp 15-16).

[219] *Id*.

[220] *Id*.

B. Other O&M Expense -- Service Restoration Resiliency Fund – The Commission should reject Consumers' proposed Service Restoration Resiliency Fund (SRRF).

MNSC believes the following is the record on this issue: Revised Direct Testimony of Company witness Andrew R. Snider, 3 Tr 2147-52; Revised Direct Testimony of Richard J. Bunch, 6 Tr 4069-71 and his exhibits CUB-23 and CUB-28; Direct Testimony of Attorney General witness Sebastian Coppola, 3 Tr 2568-91 (public) and his exhibit AG-54; Direct Testimony of Staff witness Theresa McMillan-Sepkoski, 6 Tr 4515-17, and her sponsored exhibits S-9.1 and S-9.2.

Under Consumers' proposed Service Restoration Resiliency Fund (SRRF), the Company will reserve surplus dollars from prior years to be used in future years when actual restoration costs exceed projected spend levels.[221] Consumers proposes capping the fund at $30.7 million for the test year, with any extra savings to be refunded to customers.[222] Given its unlikelihood of delivering adequate, if any, benefits to ratepayers, the Commission should reject the proposed SRRF. At this juncture, without any historic underspending data from Consumers to study, it also appears premature and unnecessary for the Commission to open a separate docket to analyze the SRRF or similar frameworks.

While the SRRF endeavors to manage Consumers' restoration underspending, the reality is that the Company has no recent underspending to manage. Consumers has repeatedly overspent on service restoration in recent years.[223] According to the recent audit of Consumers' distribution system conducted by the Liberty Consulting Group, whose findings and recommendations the Commission adopted in Case No. U-21305, between 2019 and 2023, Consumers' actual restoration costs averaged $124.8 million annually, while the Company's budgets averaged just $48.5

[221] Revised Direct Testimony of Andrew R. Snider, 3 Tr 2143.

[222] *Id*.

[223] Case No. U-21305, *Final Report to the Michigan Public Service Commission - Utility Distribution Audit for Consumers Energy - Part Two (Liberty Report)*, September 23, 2024, pp. 114-115; Case No. U-21305, Order, June 12, 2025, p 43 (adopting Liberty's findings and recommendations).

million.[224] Consumers witness Andrew Snider testified that the elimination of the five-year average as a budget baseline and recent system investments should "ease restoration spending needs" and provide "an increased likelihood of underspend."[225] However, Mr. Snider also conceded that "more frequent,"[226] "unpredictable . . . weather volatility"[227] could dull the impacts of these innovations.

For this reason, it is very possible that Consumers has no underspending whatsoever in a given future year, providing funds to neither the SRRF nor customers. As MNSC witness Richard Bunch testified, Consumers "provide[d] no evidence" to support its claim that "the likelihood of underspending should increase in the future."[228] According to Mr. Bunch, Consumers' proposal to defer costs through its Extraordinary Storm Accounting (ESA) proposal also indicates that the Company still harbors concerns with overspending.[229] Until Consumers demonstrates "sustained efficiency gains that offset the growing pressures from extreme weather," the Company's likelihood of underspending remains low.[230]

Even if Consumers does underspend in the test year, the proposed SRRF's $30.7 million cap diminishes customers' chances of reaping commensurate benefits. Regarding the cap, Mr. Bunch criticized the proposed SRRF as being even less favorable to ratepayers than the Company's previously rejected Service Restoration Cost Sharing Mechanism (SRCSM). While the SRCSM proposed to evenly divide any underspent amounts between Consumers and ratepayers, the SRRF

[224] *Id*.

[225] Snider Direct, 3 Tr 2146.

[226] Snider Direct, 3 Tr 2128.

[227] Snider Direct, 3 Tr 2146.

[228] Revised Direct Testimony of Richard Bunch, 6 TR 4068-4069.

[229] *Id*.

[230] Bunch Revised Direct, 6 Tr 4071.

creates "asymmetric benefits for the Company and its shareholders,"[231] affording "no upside to ratepayers" until the Company has reserved for itself millions of dollars.[232] Consumers offered little justification for why $30.7 million is an appropriate cap for the proposed SRRF. In his testimony, Mr. Snider merely stated that the value is based on the Company's average O&M costs for a "single potential catastrophic event" over the past three historic years, adjusted for inflation.[233]

For the above reasons, the Commission should reject Consumers' SRRF proposal.

C. Other O&M Expense – Extraordinary Storm Accounting – 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 believes the record on this issue includes the following: Revised Direct Testimony of Company witness Andrew R. Snider, 3 Tr 2147-52; Revised Direct Testimony of Richard J. Bunch, 6 Tr 4069-71 and his exhibits CUB-23 and CUB-28; Direct Testimony of Attorney General witness Sebastian Coppola, 3 Tr 2568-91 (public) and his exhibit AG-54; Direct Testimony of Staff witness Theresa McMillan-Sepkoski, 6 Tr 4515-17, and her sponsored exhibits S-9.1 and S-9.2.

The Commission should reject Consumers' Extraordinary Storm Accounting (ESA) proposal. ESA would allow the Company to defer service restoration overspending costs from "extraordinary storms" that cause at least 300,000 customer outages over a seven-day period, or that result in a State of Emergency declaration from the Governor's office.[234] The ESA proposal reveals that, in the face of growing extreme weather risks, Consumers expects its overspending pattern to continue.[235] As proposed, ESA would shield the Company and its stakeholders from

[231] Bunch Revised Direct, 6 Tr 4068-69.

[232] *Id*.

[233] Snider Revised Direct, 3 Tr 2145.

[234] Snider Direct, 3 Tr 2147.

[235] Bunch Revised Direct, 6 Tr 4069.

restoration costs without providing any reciprocal benefits to ratepayers. However, if the Commission finds merit in the idea, it should study ESA in a separate docket.

1. The Commission should reject Consumers' proposed ESA, which reduces Consumers' financial risk while exposing ratepayers to increasing restoration costs.

As extreme weather becomes more frequent, Consumers is sure to call on ESA often, if approved.[236] Approving ESA would allow the Company to justify overspending with oversight only in hindsight. Without proper controls in place, ESA is vulnerable to abuse that would erode cost savings flowing from the Company's improved budget practices and system reliability, at the expense of ratepayers.[237] The Commission should insist that Consumers achieve both timely service restoration and responsible spending, and reject ESA as proposed in this docket.

ESA has similar features to Consumers' previously rejected SRCSM.[238] Since ESA requires Consumers to demonstrate the prudence and reasonableness of its spending[239] and only allows the recovery of costs arising from "extraordinary storms," the Company's proposal is in some ways an improvement from the SRCSM.[240] Nevertheless, like the SRCSM, ESA still fundamentally reduces Consumers' financial risk and leaves ratepayers to foot the bill for increased restoration costs.[241] The proposed ESA also lacks adequate guardrails to ensure that Consumers overspends only when absolutely necessary. There is no cap on how much overspending can be deferred under

---

[236] *Id*.

[237] Case No. U-21305, Liberty Report - Part Two, pp 118-119 (finding that deferral accounting for excess storm costs *may* offer a solution for avoiding customer costs *for adverse weather that does not materialize* (emphasis added)).

[238] Case No. U-21585, March 21, 2025, Order, pp 300-301. The previously rejected SRCSM would have imposed 50% of all overspending costs onto ratepayers.

[239] Snider Direct, 3 Tr 2147.

[240] Bunch Revised Direct, 6 Tr 4069.

[241] *Id*.

ESA. As a result, the Company is not sufficiently incentivized to restore service following extraordinary storms in the most cost efficient way.[242] To justify its decision of not imposing a cost threshold, Consumers merely provided that such a cap would be "impractical."[243] The Commission should be wary of any initiative that allows the risk of overspending to be shifted to ratepayers, and it should reject any such initiative that does not have strong ratepayer protections in place.

Consumers has also failed to provide compelling examples of ESA in other jurisdictions that assuage concerns about risks to ratepayers. The Company cites examples of similar mechanisms in New Jersey and South Carolina,[244] but it does not discuss the ratepayer impacts of these examples.[245] The peer utilities highlighted by Consumers are also not sufficiently similar to the Company; they are generally smaller than Consumers, with inherently less flexibility to handle peaks and valleys in annual restoration costs.[246]

Lastly, the proposed ESA would be redundant. As Commission Staff points out, Consumers can already recover extraordinary storm costs through *ex parte* cases.[247] In one case, where the Company requested deferred accounting following an extraordinary storm, it received a ruling within as little as 37 business days.[248] While Consumers insists that ESA is necessary to "standardize" the restoration cost recovery process, it fails to articulate how such a process should

[242] *Id*.

[243] Snider Rebuttal, 3 Tr 2172.

[244] Snider Direct, 3 Tr 2150.

[245] Direct Testimony of Sebastian Coppola, 3 Tr 2573 (public).

[246] *Id*.

[247] Direct Testimony of Theresa McMillan-Sepkoski, 6 Tr 4516-17.

[248] *Id*., discussing Case No. U-21914.

be standardized.[249] Since ESA is a complex proposal with dubious incentives, it should only be adopted if a compelling need for such a mechanism is demonstrated. The Company has not demonstrated the importance of ESA, or the deficiencies of existing procedures, in this docket. For these reasons, the Commission should reject Consumers' proposed ESA.

2. If the Commission finds any merit in Consumers' ESA proposal, it should further study ESA in a separate docket.

If the Commission finds any merit in Consumers' ESA proposal, it should further study ESA in a separate docket as recommended by Attorney General witness Coppola.[250] MNSC recognizes that the Liberty audit supports exploring some version of deferral accounting, as Mr. Snider noted in his rebuttal.[251] However, as both Mr. Bunch and Mr. Coppola testified, the Company's evidence in support of ESA is not compelling and the Commission should not approve the Company's proposal in this case.

The Liberty audit recognized that growing extreme weather risks might encourage Consumers to overspend on service restoration, blunting the positive ratepayer impacts from improvements to the Company's budgeting practices and system reliability.[252] The Liberty audit also cautioned that "[i]t should not be taken for granted that escalation and worsening weather will overcome the reliability and resiliency gained by billions of dollars spent over that historical period

[249] Snider Rebuttal, 3 Tr 2173.

[250] Coppola Direct, 3 Tr 2572-73 (public); Snider Rebuttal, 3 Tr 2174.

[251] Case No. U-21305, Liberty Report, Part Two, pp 118-19.

[252] See, e.g. Case No. U-21305, Liberty Report, Part Two, pp 14. (finding that "[t]he changes that Consumers has made and is continuing to make in methods, tools, reporting and analysis with respect to asset management move the Company forward"); see also pp 114 (finding that annual service restoration costs for the period from 2019 through 2023 have averaged $124.8 million annually, while average annual budgets have averaged a fraction of that amount at $48.5 million, and that service restoration costs were particularly high in 2023). These findings suggest not only that the Company is underestimating restoration costs and seeking to recover millions of dollars that it has overspent, but that restoration costs are increasing as the years march on.

or the many more that will be spent."[253] But, recognizing that it will take time for its recommendations to improve storm restoration cost estimates to bear fruit, Liberty recommended exploring deferral accounting "[i]n the meantime" as a means for permitting recovery, so long as the overspending is reasonable and prudent.[254] Although Consumers asserts that there is "no more appropriate opportunity" than this case to explore ESA,[255] the Company has not presented sufficient evidence to justify its proposal. Therefore, if the Commission wishes to explore ESA and other deferral accounting opportunities, it should open a separate docket to do so.

D. Inflation Rates – Productivity Offset – the Commission should apply a productivity offset to test year O&M labor and non-labor costs, resulting in a disallowance of $59.5 million.

MNSC believes the record on this issue includes the following: Direct Testimony of Company witness Heidi J. Myers, 3 Tr 1833-35; Myers Rebuttal, 3 Tr 1849-56; Direct Testimony of Company witness Patrick D. Daly, 3 Tr 1050-51; Exhibit A-13, Schedule C-5.1; Exhibit A-97; Revised Direct Testimony of CUB witness Richard J. Bunch, 6 Tr 4025-48; Exhibits CUB-22, 23, 24, 25.

1. The Commission has indicated that Consumers must demonstrate how it is offsetting inflation with productivity gains.

In Case No. U-21585, MNC witness Bandyk raised concerns regarding the Company's approach to offsetting inflation pressure by productivity gains.[256] The ALJ agreed that productivity improvements may at least partially offset inflationary pressures and questioned whether the Company's "other adjustments" to O&M expenses "simulate the effect of productivity improvements on Consumers' costs."[257] The ALJ recommended accepting the Company's

[253] Case No. U-21305, Liberty Report, Part Two, p 118.

[254] *Id*. at 118-19.

[255] Snider Rebuttal, 3 Tr 2175.

[256] Case No. U-21585, December 27, 2025, PFD, pp 474-75 (citing Bandyk Direct, 5 Tr 2945).

[257] Case No. U-21585, December 27, 2025, PFD, p 475.

projection for that case but directing Consumers to present more detailed evidence showing it is actually offsetting inflation with productivity.[258] The Commission agreed with the ALJ and directed Consumers to present in its next rate case (i.e., this case) more detailed evidence to demonstrate that it is offsetting inflation by productivity.[259]

In Consumers' recent gas rate case, MSC supported applying productivity offsets to adjust the Company's cost projections using U.S. Bureau of Labor Statistic (BLS) data for labor and non-labor costs, and again urged the Commission to require Consumers to provide evidence it is offsetting inflation with actual productivity improvements in future rate cases.[260] MSC argued that the Company's preferred approach is untenable and unfair to ratepayers, and the simple approach of reducing inflation by objective reductions is reasonable.[261] The ALJ shared MSC's concern about whether Consumers adequately offsets inflation with productivity increases and found CUB's recommendation (apply productivity offset to inflation) "is an idea worthy of consideration to ensure that productivity improvements are moderating costs and providing customers with cost savings that should result from increases in productivity."[262] However, the ALJ declined in that case to adopt the recommendation to apply productivity offsets "across a wide range of O&M and labor expenses" and instead concluded the Commission should direct Consumers to present more detailed evidence "to demonstrate that it is in fact offsetting inflation with productivity increases."[263] The ALJ rejected Company arguments that this would be too burdensome because

[258] *Id.* at 475-76.

[259] Case No. U-21585, Order, March 21, 2025, pp 355-56.

[260] Case No. U-21806, PFD, August 14, 2025, pp 411-12 (citing Bunch Direct, 4 Tr 2371-81).

[261] Case No. U-21806, PFD, August 14, 2025, pp 414-15 (citing MNC initial brief, p 109).

[262] Case No. U-21806, PFD, August 14, 2025, p 416.

[263] Case No. U-21806, PFD, August 14, 2025, p 417.

the Company claims it is already considering productivity; "this direction should not be overly burdensome because it simply requires the company to more transparently highlight how such considerations are taken into account."[264] The ALJ concluded by noting that, while CUB's proposal "would certainly be simpler, easier, and less burdensome," it may be more appropriate to allow the Company to demonstrate how it accounts for productivity gains.[265] The Commission adopted the ALJ's recommendation.[266]

2. CUB witness Bunch testified that, because the Company presented only non-responsive testimony purporting to show test year cost projections reflect productivity offsets, the Commission should adopt productivity offsets to test year O&M inflation rates.

Company witness Myers presented testimony responding to the Commission's order in U-21585 directing Consumer to demonstrate how it is offsetting inflation by productivity gains.[267] She testified that isolating and quantifying productivity gains is challenging due to the timing of filing the rate case and the fact that productivity gains may be indirect or diffuse, or not quantifiable as dollar reductions. The result is that Consumers is unable to provide itemized documentation to show productivity gains by line item in witness exhibits. The testimony further points out that several programs project test year costs not simply based on inflation increases but through programmatic-specific methods, referencing testimony from witnesses Stewart, Baker, Byrom, Blumenstock, Snider, Foster, and Guinn in support.

CUB witness Bunch addressed the issue of productivity gains – including the Company's case – comprehensively. First, Bunch reiterated the concerns associated with simply passing along

[264] *Id.*

[265] *Id.*

[266] Case No. U-21806, Order, September 30, 2025, pp 242-44, 247.

[267] Myers Direct, 3 Tr 1833-35.

inflation costs to customers.[268] Companies operating in competitive markets are constrained from recovering 100% of cost increases by raising their prices because their customers would take their business elsewhere or simply reduce consumption. Regulated monopoly utilities, for the most part, cannot lose customers and experience inelastic demand for their services, and thus face little direct pressure to contain their costs. Bunch identified a number of opportunities for companies in competitive environments to manage inflationary pressures to offset cost increases – running equipment faster or longer, keeping older equipment longer, seeking new suppliers of goods and services, modifying production methods, investing in ways to increase labor productivity, adjusting output levels, and in other ways to avoid passing rising costs to customers.

These productivity opportunities are not limited to competitive environments – utilities have access to the same arsenal of managerial responses, though utilities may suffer from lack of motivation if the regulator approves rate increases to fully offset inflation.[269] Bunch testified in support of regulatory review as a proxy for market forces by establishing a reasonable expectation for a utility to demonstrate that it is achieving productivity gains similar to companies in competitive markets. This does not require absolute consistency across all programs; instead, the Commission should focus on limiting increases in overall costs and revenues, leaving it to the discretion of utility management to balance cost increases from area to area. Bunch testified there may be situations where increased costs are justified, such as increasing sales and when new statutory or performance requirements justify cost increases above productivity-adjusted

[268] Bunch Direct, 6 Tr 4026-28.

[269] Bunch Direct, 6 Tr 4028.

inflation.[270] Even in these areas, however, the utility can realize productivity improvements, just as an unregulated company would do faces with the same kinds of pressures.

After reciting the regulatory context for productive-adjusted inflation (discussed above), Bunch addressed the Company's proposed inflation factors, including the testimony referenced by Company witness Myers to support the Company's inflation adjustments.[271] Company witness Daly presents the Company's proposed inflation factors as follows:[272]

	2025	2026	2027 (prorated to 4 months)
Consumers Proposed Inflation	2.1%	2.4%	0.8%

Bunch addressed the inconsistent way the Company applies these inflation rates, obscuring its test year cost projections. He cited Exhibit A-13 Schedule C-5.1 showing inflation factors applying to various work groups, but points to two examples where Company witnesses support an alternative basis for projected cost increases (merit salary factor for 3.2% increases for Defined Company Contribution Plan and Savings Plan costs; "zero-based accounting" resulting in 5.1% increase for Customer Experience and Operations O&M costs, notwithstanding historic annual declines in program costs).[273] Bunch also identified Forestry Operations as an example where inflation (and other) adjustments are embedded in increases but not specifically identified.[274] Inflation increases for capitalized costs are similarly untransparent, unclear, and inconsistent.[275] The impact of the

[270] Bunch Direct, 6 Tr 4029.

[271] Bunch Direct, 6 Tr 4031-40.

[272] Daly Direct, 3 Tr 1050.

[273] Bunch Direct, 6 Tr 4032-33 (citing Exhibit A-97, p. 2; Grob Direct, 3 Tr 1142=43; Exhibit A-53, p 4; Byrom Direct, 3 Tr 967.5). See also Ex CUB-24, p 2 (list of expenses and exhibits that "show inflation as if it's being used to project an expense, but do not actually use it in the projection.").

[274] Bunch Direct, 6 Tr 4033-34 (citing Exhibit A-13, Schedule C-5.1; A-175; Stewart Direct, 3 Tr 2220).

[275] Bunch Direct, 6 Tr 4034 (citing Exhibit CUB-24, Company Response to U-21870-SA-CE-113 & 114; Exhibit A-12, Schedule B-5).

various ways the Company reflects cost increases from the historic to projected periods results in 21.4% increase in O&M and 62.8% increase in capex, or 32.5% in total labor and 52.5% in total non-labor, during the same period where the compound inflation rate is 5.39%:[276]

Next, CUB witness Bunch reviewed Company witness Myers' testimony offered in response to the Commission directive in U-21585 to show that the Company offsets inflation with productivity gains.[277] As Bunch explained, the referenced witness testimony does not show that productivity gains are reflected in Company cost projections. Zero-based budgeting does not in itself indicate whether and how the budget reflects productivity offsets. Modifying the baseline (using a 5-year average instead of single historical year) says nothing about productivity. According to Bunch, the Company presented essentially the same inapposite arguments the Commission found insufficient in U-21585, albeit at greater length.

Because the Commission has indicated support conceptually for the Company to incorporate productivity offsets, and because the Company's case falls short of providing a real path to do so, CUB witness Bunch proposed that the Commission adopt a productivity offset for labor and non-labor for O&M expenses.[278] He recommended the productivity offset inflation across all programs to arrive at a total spending target. He recommended delaying application of a productivity factor to capital investments based on the principle of gradualism – to phase in the methodology.[279] He notes that the Commission previously opted to give the Company an opportunity to demonstrate how it incorporates productivity as opposed to adopting the similar proposal presented by MNC witness Bandyk in U-21585, but given the dearth of evidence showing

[276] Bunch Direct, 6 Tr 4035-36, Table 1.

[277] Bunch Direct, 6 Tr 4036-39.

[278] Bunch Direct, 6 Tr 4040-47.

[279] Bunch Direct, 6 Tr 4042-43, 4044.

the Company is incorporating productivity offsets to inflation increases, the proposed alternative approach should be adopted. In response to the argument that Bunch's productivity offset is "overly simplistic," Bunch counters that his approach is "straightforward, transparent, and less burdensome," and also no more "simplistic" than applying an inflation factors across the board.[280]

Bunch recommended employing the compound annual change in BLS labor productivity for Michigan's private, non-farm sector, which is "the most narrowly tailored productivity factor reasonable descriptive of the Company's labor market."[281] For non-labor, Bunch recommended employing the BLS Total Productivity Factor for the US private non-farm business sector, which "is a measure of economic performance that compares the amount of goods and services produced (output) to the amount of combined inputs used to produce those goods and services."[282] This approach results in productivity-adjusted inflation rates for labor and non-labor as follows:[283]

	2025	**2026**	**2027 (prorated 4 months)**
Consumers Proposed Inflation	2.1%	2.4%	0.8%
Labor Productivity			
BLS Labor Productivity	1.34%	1.34%	0.45%
CUB Labor Productivity-Adjusted Inflation	0.76%	1.06%	0.35%
Non-Labor Productivity			
BLS Non-Labor Productivity	0.8%	0.8%	0.3%
CUB Non-Labor Productivity-Adjusted Inflation	1.29%	1.59%	0.53%

Applying these adjustments to test-year O&M projections, and removing forestry O&M from the analysis to reflect the ramp-up in line clearing work planned for the test and future years (discussed below), these adjustments result in a total disallowance of $59.5 million in proposed O&M expenses. Bunch also recommended the Commission direct Consumers to present both O&M and

[280] Bunch Direct, 6 Tr 4043-44.

[281] Bunch Direct, 6 Tr 4045.

[282] Bunch Direct, 6 Tr 4045-46.

[283] Bunch Direct, 6 Tr 4045, Table 2 (Labor), Table 3 (Non-Labor).

capital test-year cost baseline projections calculated as historical cost adjusted for productivity-adjusted inflation, acknowledging that the Company may additionally present "other adjustments" with demonstration of why they are necessary due to sales changes or new statutory or performance requirements, though "other adjustments" should not embed inflation.[284]

3. The Company offers only unpersuasive rebuttal arguments.

Company witness Myer opposed Bunch's recommendation.[285] Witness Myers first asserts that witness Bunch, at 6 Tr 4025, "mischaracterizes my direct testimony in this case," noting she did not at 3 Tr 1833 characterize incorporating productivity gains as "unnecessary."[286] Bunch testified that the Commission directed the Company to address incorporating productivity gains into cost projections, and that Consumers "has not done so and argues that the undertaking is unnecessary."[287] While Bunch did not specifically attribute the argument to Myers direct testimony, and Myers admittedly did not testify precisely that additional detail is "unnecessary," her direct testimony does suggest the Company believes it is unnecessary to provide additional detail about productivity gains because such detail is generally absent from the Company's case. Moreover, the rebuttal testimony – in particular, the argument that it is inappropriate to expect regulated utilities to respond to cost pressures the way unregulated companies[288] – further suggests the Company finds it unnecessary to identify productivity offsets to offset inflation pressure.

Next, witness Myers affirms that Company witnesses do not present inflation consistently in their exhibits, maintaining their approaches are fully supported, irrespective of their

[284] Bunch Direct, 6 Tr 4048.

[285] Myers Rebuttal, 3 Tr 1849-56.

[286] Myers Rebuttal, 3 Tr 1849.

[287] Bunch Direct, 6 Tr 4025.

[288] Myers Rebuttal, 3 Tr 1851, 1853.

inconsistency.[289] Witness Bunch explained that the inconsistent approaches to inflation results in unnecessary obscurity, particularly the extent inflation is modified by "Other Adjustments" that are unclear and spread across numerous witness testimonies and exhibits. Fully supporting the inconsistent approaches does not rectify the inconsistency – they are still inconsistent (and obscure). Moreover, where testimony reveals cost increase approaches that deviate from the inflation methodology shown in Exhibit A-13 Schedule C-5.1, that does not prove that the various methods are fully supported, it supports that Exhibit A-13 Schedule C-5.1 is misleading.

Witness Myers next defends the Company's approach of including various additional adjustments as "Other Adjustments," which account for the bulk of the Company's projected cost increases in the test year, because "that is exactly what that column is supposed to represent."[290] The rebuttal misses the point of Bunch's testimony, which is not which column reflects increases but that "the Company's projected costs are increasing much faster than inflation."[291] The meta-point here is that, while inflation increases are high (and reflect no productivity gains), the Company's overall cost increases are *even higher* than these high inflation rates. Bunch's principal concern – and the premise of his productivity analysis – is the overall decreasing affordability of Consumers' electricity for its customers, especially its residential customers, while rate increases outpace even inflation increases.[292] While the rebuttal addresses testimony not specifically complaining about the "Other Adjustments" column, it is worth noting that the "Other Adjustments" column lacks notations explaining the variety of adjustments reflected in those

[289] Myers Rebuttal, 3 Tr 1850.

[290] Myers Rebuttal, 3 Tr 1850.

[291] Bunch Direct, 6 Tr 4036.

[292] Bunch Direct, 6 Tr 4018-24 (discussing burden of residential rate increases and relative rate of inflation to rate increases).

adjustments.[293] It is only in reviewing testimony that the rationale for the bulk of spending increases become evident.

Next, witness Myers opposes the perspective that the Company has managerial discretion to respond to inflationary pressures, noting the Company's "obligation to serve their customers" and meet "safety, service quality, and reliability" expectations.[294] According to Myers, "regulated utilities are fundamentally different than unregulated companies" and have "unique regulatory obligations," in particular, "the obligation to serve," which may cause regulated utilities "to respond to cost pressures differently than unregulated companies."[295] These are obviously not mutually exclusive opportunities – a utility may respond to inflationary pressures by, for example, extending the service life of equipment while also serving customers. Both regulated and unregulated corporations must adhere to safety, service quality, and reliability expectations – the difference is that unreliable businesses or those with poor service quality will lose customers and market share, while utilities generally will not. Both also have obligations to ensure safe conditions for employees, contractors, and the public – that is a societal expectation for all responsible businesses, it is not unique to regulated utilities. The Company's resistance to the idea that productivity gains should even apply to a regulated utility is revealing.

Moreover, the suggestion that regulated utilities should be exempt from a regulatory expectation of achieving demonstrable productivity offsets *because* it is a regulated electric utility wholly misses the point here. Ascertaining whether and how Consumers achieves productivity gains is precisely because the utility operates outside a competitive market; absent a clear

[293] See, e.g., Ex A-13, Sch C-5.1; Ex A-128; Ex A-175, p 2; Ex A-43, p 2; A-53; A-97.

[294] Myers Rebuttal, 3 Tr 1851-52.

[295] Myers Rebuttal, 3 Tr 1853.

regulatory expectation (supported by utility evidence) that the utility will achieve efficiency offsets to control costs, the incentive to do so is inherently lacking. Arguing 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. The Commission should not accept the argument that regulated utilities should not be expected to demonstrate that they are efficient, achieving productivity benefits by investments in staff and equipment, reviewing and improving the ratio of outputs to inputs, and other standard management practices to maintain cost control. The alternative is ever-increasing costs without correlative improvements in performance, higher sales, or other efficiencies.

Next, Company witness Myers responds to the recommendation that the Commission constrain O&M labor and non-labor cost increases by inflation adjusted for productivity unless additional adjustments are warranted based on sales, legal, or performance requirements.[296] The rebuttal notes that spending increases "enable[] productivity gains and improved reliability" and support outage reductions, grid modernization, and other strategic goals. According to Myers, increasing spending does not reflect a "failure to achieve productivity," but are instead foundational to delivering reliability, safety, and operational efficiency. This testimony reflects a fundamental misunderstanding of "productivity" – which is producing more output with fewer inputs, not more inputs. Increasing spending to "enable productivity gains" is the opposite of productivity. It further misunderstands that improved reliability is a performance standard; spending more to ensure more reliable service doesn't mean Company has become more productive. If the Company improves reliability at same costs as before, then it would be a

[296] Myers Rebuttal, 3 Tr 1852-53.

productivity gain. The assertion that higher spending is "foundational" to achieve "operational efficiency" makes no sense. The foundation of "operational efficiency" is not *increased* spending, the foundation of "operational efficiency" is either *less* spending to produce consistent operations, or it is the *same* spending to produce more outputs. It is not logical to assert that increased spending is necessary to deliver operational efficiency. Moreover, to the extent Company spending has consistently increased in recent years, and to the extent increased spending produces improved reliability or operational efficiency, as the rebuttal asserts, then the Company should easily be able to identify improved reliability or productivity gains resulting from recent spending increases, but it has not.

Rather than constraining spending increases across the board, Myers suggests the test should be whether the individual program expenditures are reasonable and prudent. This approach suffers at least three problems. The first is that, because of information asymmetry, utilities naturally have the most complete understanding of their cost structures, which makes them best positioned to rebalance spending across programs to achieve the best overall outcome. The Commission should keep them accountable to overall spending standards rather than trying to make programmatic budgeting decisions on behalf of the Company in face of incomplete information. Moreover, without a portfolio-level benchmark, such as PAI that Bunch supports, the individual program review relieves Consumers of its managerial responsibility to balance costs prudently to the Commission and intervenors to parse each individual expenditure. Finally, the Commission's attempt to obtain program-level productivity gains has been largely unsuccessful, given the record in this case.

Witness Myers' assertion that 93% of the recommended disallowance is attributable to electric distribution O&M is inaccurate.[297] Bunch's recommendation is an across-the-board reduction of $59.5 million to reflect productivity gains across 16 program areas (excluding Forestry).[298] As shown in Table 4, the $47.7 million reduction for the Electric Division – Electric & Common may be the single largest contributor to the disallowance, but it does not account for 93% of the disallowance. Various IT programs contribute $31.154 million.[299] Employee-related programs contribute nearly $5 million to the disallowance.[300] Distribution is not the main program area where the Company may achieve productivity gains, as reflected in Bunch's analysis. Some disallowances are offset by positive PAI adjustments for generation costs, strengthening the argument that the focus should be on *overall* spending target with the Company retaining flexibility to allocate dollars among programs, while still being held accountable to the overall productivity standard. Moreover, Bunch anticipated the Commission may authorize higher-than-production-adjusted-inflation spending levels to achieve new performance standards, but the Company has not attempted to demonstrate that it is stiving to achieve new performance standards except by improving reliability with increased forestry expenditures, which Bunch proposes to exempt from the calculated disallowance. Furthermore, the Company's plans to invest increasing levels of O&M on the distribution system is a reason to find operational and cost efficiencies (productivity benefits) in other program areas to ensure the overall cost of delivering safe, reliable service remains reasonable and prudent for customers.

---

[297] Myers Rebuttal, 3 Tr 1854.

[298] Bunch Direct, 6 Tr 4047.

[299] *Id.* at Table 4 (Information Technology Operations, Information Technology Investments, Information Technology - Security Operations, Information Technology - Security Investments).

[300] *Id.* (Defined Company Contribution Plan; 401(k) Employees' Savings Plan; Active Health Care/Life Insurance/LTD; Other Benefits; Corporate Services; Incentive Compensation).

Company witness Kelly also takes issue with Bunch's recommendation to reduce test year O&M by $59.5 million, arguing that this would "simply cause deterioration on the system to rapidly accelerate."[301] Witness Kelly cites no evidence to support this sweeping allegation. As discussed, the recommendation supports significant investment in key reliability-driving programs (forestry, LVD pole replacement) and continued increases in other programs at controlled level.

Finally, Myers' rebuttal mischaracterizes Bunch's recommendation as "simply a cap[]" on expense levels, but that is not accurate. The recommendation is to disallow $59.5 million in the test year because the Company has not demonstrated that its proposed O&M expense increases are reasonable and prudent by failing to effectively estimate and incorporate productivity gains in their costs development process. The recommendation specifically anticipates opportunities for increases above productivity-adjusted inflation. Finally, the recommendation is directly responsive to the Commission's directive in U-21585, requiring Consumers to demonstrate that productivity is incorporated in its expense projections. Instead of doing so, in rebuttal, the Company has made clear that it should not be expected to achieve demonstrable productivity offsets because it is a regulated utility, and it has revealed its fundamental misunderstanding of productivity—treating higher spending as evidence of productivity rather than demonstrating how it will produce more output with fewer inputs. The Commission should adopt the recommendations of CUB witness Bunch and disallow $59.5 million for the reasons discussed above.

[301] Kelly Rebuttal, 3 Tr 1617.

V. COST OF SERVICE

A. Distribution Cost Allocation

1. Consumers' Voltage Differentiation Does Not Reflect Cost Causation and May Disproportionately Allocate Costs to Lower-Voltage Classes.

MNSC believe the following portions of the record are relevant to this issue: Direct Testimony of Company witness Emily Davis, 4 Tr 2650-56; Davis Rebuttal, 4 Tr 2669-72; Davis Cross, 4 Tr 2677-2702; Rebuttal Testimony of Company witness Scott McPhail, 3 Tr 1752-53; Ex A-129, Consumers Reliability Roadmap (2025-2029); Direct Testimony of MNSC witness Caroline Palmer, 6 Tr 3918-21; Ex MEC-17, discovery response MNSC-CE-0222; Rebuttal Testimony of ABATE witness Brian Andrews, 6 Tr 3829-31; and Rebuttal Testimony of Kroger witness Jared Robertson, 5 Tr 3420-24.

In this case, Consumers proposes to change the methodology by which the Cost of Service Study (COSS) allocates the costs of distribution assets – including substations, overhead and underground lines, and land. Where previously Consumers allocated the cost of these assets based on class peak at the voltage level of the asset, the Company now proposes to allocate these assets based on class peak at the highest voltage level of facilities downstream of the asset. Consumers has the burden of proving that this change ensures the establishment of electric rates equal to the cost of providing service to each customer class, and that each class will be assessed for its fair and equitable use of the electric grid. The Company has not met this burden, for several reasons.

First, Consumers does not know the cost consequences of the change, having not assessed them. It is obvious that relieving customers taking service at higher voltage of cost responsibility and shifting those costs to customers at lower voltage will benefit large customers at the expense of small ones – ABATE and Kroger support the change for that reason. Yet Consumers has not even tried to determine what the cost consequences will be. The Company is asking the Commission to approve a change in cost allocation without presenting the impacts of that change on the various customer classes.

Second, the new method does not ensure that costs are allocated based on cost causation because it assumes that users on the upstream side of distribution assets receive no benefit whatsoever from those assets. But two-way power flows already exist on Consumers' system, so the assumption is false. Consumers argues that such flows are minimal now, but the Company plans to increase them. Yet, once this change is approved (if it is), the Company has no plans to revisit it in the future as two-way power flows increase – making it difficult or impossible to claw some of the cost shifts back.

a. Overview of Consumers' proposed change to distribution cost allocation.

Consumers Energy witness Emily Davis testified that the COSS relies on a new Electric Asset Categorization (EAC) report to break out distribution plant "into more detail to facilitate allocating costs to customers."18F[302] The report is not in evidence. While Ms. Davis justifies creation of the new EAC report based on the need to update technology and processes,[303] the Company proposes in this case to use the report to make an important change to its method of allocating distribution costs. Whereas the Company used to allocate the cost of distribution assets based on class peak at the highest voltage connected to the asset, the new method allocates costs based on the highest voltage level downstream of the asset.[304] The upstream or high side voltage connected to the asset would no longer bear any cost responsibility for the asset.[305] Ms. Davis

[302] Davis Direct, 4 Tr 2650.

[303] *Id*. at 2651.

[304] Davis Direct, 4 Tr 2652-53; Palmer Direct, 6 Tr 3918.

[305] Davis Cross, 4 Tr 2690.

stated that the allocator used is still class peak.[306] However, the Company is proposing to change how it determines what customers to apply that allocator to, as explained above.

For example, in the COSS approved in Case No. U-21585, the cost of high voltage substations at voltage level 1 were allocated to all customers at voltage levels 1, 2, 3, and 4.[307] By contrast, under the proposal in this case, if customers downstream of the substation take service at voltage levels 2, 3, and 4, then only those customers would have cost responsibility for the substation – customers taking service at voltage level 1 would no longer have any cost responsibility for the voltage level 1 substation.[308]

b. Consumers Energy 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.

The statute governing cost of service states:

> Except as otherwise provided in this subsection, the 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.[309]

In this case, Consumers takes pains to avoid calling the choice to allocate the cost of distribution assets only to downstream customers a change in method – instead characterizing it as an "update."[310] However, plainly it is a change in method. Consumers did not allocate distribution

[306] Davis Direct, 4 Tr 2653, 2654, and 2655. The class peak method allocates distribution costs relative to each customer class's independent (non-coincident) peak demand. Case No. U-20963, Order, December 22, 2021, pp 345-46.

[307] Davis Direct, 4 Tr 2652.

[308] Davis Direct, 4 Tr 2652; Davis Cross, 4 Tr 2690.

[309] MCL 460.11(1).

[310] Davis Direct, 4 Tr 2659, 2664; Davis Rebuttal, 4 Tr 2670; Davis Cross, 4 Tr 2679 and 2680.

plant costs in this way previously.[311] The EAC report adds new and revised COSS categories that did not exist before.[312] The Commission has not previously approved allocating these costs only to downstream customers.[313] And it has cost consequences.[314]

The significance of the fact that the Company's proposal is a change is the burden of proof and persuasion. "Proponents of modifications to the existing cost allocation method bear the burden to demonstrate that the methods that they respectively advocate 'better ensure rates are equal to the cost of service' than the current method."[315] Because Consumers proposes to change the method for allocating distribution plant costs, the Company has the burden to demonstrate that the changes are reasonable and prudent.

c. Consumers Energy has not met its burden because it has not presented the cost consequences of the proposed change and the change relies on a false assumption that users on the upstream side of distribution assets receive no benefit from those assets.

Consumers has not met its burden to prove its proposal will ensure 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. First, the proposal has cost consequences, but Consumers does not know what those consequences are.[316] The Company has not assessed them, and the change is included in both versions 1 and 2 of the COSS. It is worth noting that in version 2 of the COSS, Consumers proposes to increase residential rates by $336 million, but to *decrease* primary rates by

[311] Davis Cross, 4 Tr 2690 and 2695.

[312] Davis Direct, 4 Tr 2653.

[313] Davis Cross, 4 Tr 2688-90. Ms. Davis argued that the change is directionally consistent with the Commission's intent with respect to allocating distribution costs. *Id*. at 2688-89.

[314] *Id*. at 2691-92 and 2695.

[315] Case No. U-17689, Order, June 15, 2015, pp 32-33.

[316] Davis Cross, 4 Tr 2691-92 and 2695-96.

$300,000.[317] While MNSC does not claim that the proposed change in distribution cost allocation accounts for all or perhaps not even most of the cost shift embedded in these numbers, it undoubtedly has some impact, and Consumers has not tried to demonstrate otherwise. The Commission should not adopt a change in cost allocation without any information about the cost consequences of the change.

Second, MNSC witness Caroline Palmer testified that "the power system is changing such that DERs [distributed energy resources] 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."[318] Consumers Energy's own Reliability Roadmap exhibit emphasizes the importance of "[b]i-directional power flows, especially in circuits that show a propensity to higher-than average adoption of solar DG [distributed generation]."23F[319] Consumers anticipates between 2.4 and 3.5 GW of solar DG by 2030, causing "two-way flows."24F[320] Consumers also justifies the importance of a DER Management System ("DERMS") in part based on the described bidirectional power flow, calling a DERMS "critical for managing bi-directional power flows."25F[321]

[317] Davis Direct, 4 Tr 2662, Table 11, $2,657.6 million of version 2 proposed residential revenues minus $2,321.4 million of present residential revenues equals $336.2 million; and $967.8 million of version 2 proposed primary revenues minus $968.1 million of present primary revenues equals ($0.3 million).

[318] Palmer Direct, 6 Tr 3919.

[319] Exhibit A-129, Reliability Roadmap, p 34.

[320] *Id.* at 35.

[321] *Id.* at 142.

Ms. Palmer testified that "[c]learly, Consumers is increasingly planning and designing its power system to be bidirectional."[322]

Consumers agrees that power on its system can flow from lower-voltage distribution equipment to higher-voltage distribution equipment – and even from distribution-level equipment to transmission-level equipment.28F[323] Because power sometimes flows from lower to higher voltages on the Company's system now, and the Company plans to increase the amount of power flowing in that direction as it connects more distributed solar in the future, 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. It is not consistent with cost causation to assign upstream voltage zero cost responsibility for equipment if more than zero power is flowing upstream. Further, the assumption that no power flows upstream will grow less accurate as time goes on and Consumers connects more distributed solar to its system.

In rebuttal, Consumers argued that the amount of bidirectional power flow on Consumers' system is "de minimis" and therefore should not be considered when evaluating the proposed change.[324] Consumers witness McPhail stated the Company is not currently able to comprehensively track bidirectional flow across its entire system.[325] While that may be true, Consumers acknowledges that such flows do exist, and so the premise of the proposed change – that power flows only from that high side to the low side of distribution assets – is just not true. Further, the change is counter to the trend of increasing such flows that Consumers emphasizes

[322] Palmer Direct, 6 Tr 3920.

[323] Ex MEC-17, Response to MNSC-CE-0222(c).

[324] Davis Rebuttal, 4 Tr 2671; McPhail Rebuttal, 3 Tr 1752-53.

[325] McPhail Rebuttal, 3 Tr 1753.

repeatedly in its reliability roadmap and that witness Davis agreed is likely to occur.[326] 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. Moreover, if approved, Consumers has no plans to revisit the new allocations as it implements the distribution plan and bidirectional flows increase.[327]

d. Responses to ABATE and Kroger

Unsurprisingly, ABATE and Kroger – as beneficiaries of the proposed change – support it and filed rebuttal to MNSC witness Palmer. ABATE witness Brian Andrews faulted Ms. Palmer for providing "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 network."[328] While he acknowledged that "distributed generation can cause limited instances of reverse flow at the local level, neither Ms. Palmer nor Consumers have presented any evidence that such flows are significant or system-wide."[329] He asserted that "[a]dopting her proposals would improperly shift costs away from the low-voltage residential and commercial customers which cause them and on to higher-voltage commercial and industrial customers . . ."[330]

However, Mr. Andrews is either confused or attempting to shift the evidentiary burden. As detailed above, Consumers is proposing to change how it allocates distribution costs. The change is based on the premise that costs should only be allocated to customers taking service at voltage levels downstream of distribution assets because power only flows in that direction. Ms. Palmer

[326] Davis Cross, 4 Tr 2700-01.

[327] *Id*. at 2701-02.

[328] Andrews Rebuttal, 6 Tr 3829-30.

[329] *Id*. at 3830.

[330] *Id*. at 3831.

provides evidence that the Company's premise is not accurate – and will be less accurate in the future based on Consumers' own plans. It is not Ms. Palmer's burden to demonstrate that the change should not be made – it is Consumers' burden to demonstrate that it should.

Kroger witness Jared Robertson claims that even if high-voltage customers benefit from power flowing up from the lower voltage distribution system, that does not mean such customers cause any of the costs of the lower voltage system. MNSC responds to similar arguments about benefitting from costs versus causing costs in the section on AMI cost allocation, below. Mr. Robertson also makes similar arguments to ABATE that bidirectional power flows on Consumers' system are not extensive now, and that Ms. Palmer should have the burden to demonstrate that her position – opposing Consumers' proposed change – preponderates. MNSC relies on the response to ABATE, above, with respect to these arguments.

. . .

In summary, Consumers proposes a change that will shift costs from primary customers to residential customers – but does not know by how much. Consumers proposes to do so by eliminating all cost responsibility of customers for distribution assets at their voltage level and allocating all costs for such assets to customers who take service at lower voltage levels downstream of the assets. Consumers relies on a premise that the customers on the high side of the assets receive no benefit from the assets because power flows only from the high side to the low side – but that is not true. Further, Consumers plans increased connection of DERs to its system that will grow these bidirectional flows. The Company has not demonstrated that it would be reasonable, prudent, or equitable to shift an unknown amount of cost from primary to residential customers based on a premise that is not accurate, will be less accurate going forward, and is very unlikely to be revisited if it is approved. For these reasons, the Commission should deny approval

of the 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.

2. The Way Consumers Justifies Distribution Reliability Improvements Among Customer Classes Conflicts with the Way It Allocates Distribution Costs Among Customer Classes.

MNSC believe the following portions of the record are relevant to this issue: Direct Testimony of CUB witness Bunch, 6 Tr 4055-60; and Rebuttal Testimony of Company witness Emily Davis, 4 Tr 2668-69.

CUB witness Bunch testified about Consumers' methodology for allocating reliability improvements and reliability spending among the residential customers and commercial and industrial (C&I) customers, both small and medium/large.[331] He noted that the Company allocates distribution system investments for line clearing and the LVD and HVD systems using allocation that generally allocate most of the costs to residential customers.[332] In particular, the residential class is allocated at least 50% and up to 67% of all non-HVD capital and operational expenditures, plus a portion of HVD spending. Meanwhile, to justify significant distribution system investments to improve customer reliability, Consumers allocates the benefits of these investments disproportionately to the commercial and industrial class – per the Company's model, about 2% of the benefits accrue to residential customers while over 90% of the benefits accrue to small C&I customers.[333] This reflects that the economic impact of an outage is substantially larger for non-resident than residential customers.[334] What this dichotomy means in practice is that residential

[331] Bunch Direct, 6 Tr 4055-57.

[332] Bunch Direct, 6 Tr 4056, Table 7.

[333] Bunch Direct, 6 Tr 4057.

[334] Bunch Direct, 6 Tr 4058.

customers pay substantially more than the value of the benefits they receive.[335] Bunch referenced line clearing as illustrative: for the period from 2025 to 2030, Consumers anticipates $1.2 billion in LVD line clearing; residential customers will be allocated $773 million of the cost but will receive approximately $116 million in reliability benefits. Bunch recommended the Commission require the Company to analyze its allocation methodology to address the misalignment between the Company's methods for distribution cost allocation and distribution benefit allocation.[336]

Company witness Davis addressed these concerns in rebuttal.[337] She noted that the Company has not changed its modeling approach to justifying the reliability benefits of reliability investments, and those investments are allocated in the Cost-of-Service Study (COSS) using Commission-approved allocators. She notes that it is unclear how, practically, the Company would allocate reliability investments independent of other distribution investments, nor what level of study or resources would be required to isolate the costs of reliability-justified investments in the COSS. She suggests that Bunch may develop and propose specific changes for consideration, but the Company should not be ordered to do so.

In light of the ripe distribution cost allocation issue discussed in the preceding section, this is an issue that may be deferred to a future proceeding. MNSC maintain that the Company's approaches to allocating the costs and the benefits of reliability-driven investments – which are identifiable, significant, and growing – are irreconcilable and unfair to residential customers. At the same time, while the disproportionate impacts are growing as reliability-driven investments

[335] Bunch Direct, 6 Tr 4059.

[336] Bunch Direct, 6 Tr 4060.

[337] Davis Rebuttal, 4 Tr 2668-69.

increases, this is not a new problem; beyond acknowledging the conflict, MNSC supports taking no action on this issue in this proceeding.

3. Consumers should allocate distribution battery costs to all distribution customers.

MNSC believe the following portions of the record are relevant to this issue: Davis Direct, 4 Tr 2653; Davis Rebuttal, 4 Tr 2671-72; Davis Cross, 4 Tr 2708-11; Palmer Direct, 6 Tr 3921-22; and Ex MEC-18, Response to U21870-MNSC-CE-0214.

Consumers allocates batteries on the distribution system only to low voltage customers.[338] Consumers justifies this allocation as being consistent with the way the COSS treats other demand-related distribution plant and allocates costs to the customer classes connected downstream of the voltage level of that equipment. [339]

MNSC witness Palmer testified that it is not reasonable to allocate distribution battery costs only to low voltage customers because Consumers has not demonstrated that batteries serve only low voltage customers.[340] The Company is "not aware of any engineering literature or manuals that specifically state" that batteries serve only voltage level 3 and 4 customers."[341] In fact, distribution-related battery plant provides services that benefit customers across all distribution voltage levels.[342] Consumers notes that they are "deployed to support the electric distribution system (e.g., capacity deferral, voltage support, resiliency, etc.)."[343] Therefore, the allocation of these costs should not be limited to the lowest-voltage customers.

---

[338] Davis Direct, 4 Tr 2653.

[339] *Id*.

[340] Palmer Direct, 6 Tr 3922.

[341] *Id*. and Ex MEC-18, Response to U21870-MNSC-CE-0214.

[342] Palmer Direct, 6 Tr 3922.

[343] Ex MEC-18, Response to U21870-MNSC-CE-0214.

In rebuttal, Consumers witness Emily Davis first stated that the Company began allocating distribution battery costs in this manner in Case No. U-21389, "with no objections from Staff and intervenors."[344] That may be, but it does not preclude a party from raising about the allocation in all future proceedings.

Ms. Davis also testifies that "the only distribution batteries in service are connected to the LVD system which is why they are allocated to LVD customers."[345] She imputes Ms. Palmer's position to be based on bi-directional power flow,[346] but Ms. Palmer never said that. Ms. Palmer said that the capacity deferral, voltage support, and resiliency benefits cited by Consumers to justify battery investments serve the whole distribution system – not just the lowest-voltage parts of it.[347] When asked about her understanding of these benefits, Ms. Davis disclaimed any knowledge.[348]

B. IT Cost Allocation

1. Consumers should allocate the cost of the Multi-Account Online Account Management project to commercial and industrial customers because they are the only customers who use it.

MNSC believe the following portions of the record are relevant to this issue: Davis Direct, 4 Tr 2657-58; Davis Rebuttal, 4 Tr 2674-75; Palmer Direct, 6 Tr 3923-24; and Ex MEC-23.

In Case No. U-20963, the Commission required that Consumers' COSS separate out and allocate the costs associated with Digital Customer Operations IT projects, including the C&I

[344] Davis Rebuttal, 4 Tr 2671.

[345] *Id*.

[346] *Id*.

[347] Palmer Direct, 6 Tr 3922.

[348] Davis Cross, 4 Tr 2710-11.

Online Account Management project.[349] Since then, Consumers has changed the project scope and name. It is now known as the Multi-Account Online Account Management ("MAOAM") project and has expanded to give all customers the ability to manage multiple accounts through a single login.[350] The Company now takes the position that "it should be allocated in the same manner as other IT projects," – to all customer classes, including residential customers.[351] However, MNSC witness Palmer noted that "while all customers might have the ability to manage multiple accounts through a single login, it is unclear that the residential class requires such functionality."[352] Currently, there are no customers with MAOAM login for multiple accounts, and only C&I customers have access to and use the current tool.[353] Yet, Consumers proposes to use to allocate almost 63 percent of these costs to residential customers.[354] As that proposal does not allocate costs based on cost of service, Ms. Palmer recommended "that Consumers continue to break out this project cost in the COSS and allocate it to the customer classes who use the program" – which at this time is only C&I customers.[355]

In rebuttal, Consumers witness Emily Davis acknowledged that the current tool "is only available to C&I customers" but asserted that "does not reflect future utilization of the MAOAM tool which will be made available to all customers."[356] While that may be the case someday, it is

[349] Davis Direct, 4 Tr 2656.

[350] Palmer Direct, 6 Tr 3923.

[351] Davis Direct, 4 Tr 2657-58.

[352] Palmer Direct, 6 Tr 3923.

[353] Ex MEC-23, disc resp MNSC-CE-0215(b).

[354] Palmer Direct, 6 Tr 3924.

[355] *Id*.

[356] Davis Rebuttal, 4 Tr 2674-75.

not the case now. Until then, the MAOM costs should be allocated to C&I customers, because Consumers concedes that they are currently the only customers who can or do use it.

C. MNSC's recommendations concerning data center cost allocation were largely addressed in the Commission's Order in Case No. U-21859.

MNSC believe the following portions of the record are relevant to the issues in this case involving the LED rate: Direct Testimony of MNSC witness Caroline Palmer, 6 Tr 3924-29; and Rebuttal Testimony of Consumers Energy witness Laura Connolly, 3 Tr 167-68.

In this case, MNSC witness Caroline Palmer also offered testimony and recommendations regarding cost allocation for data centers.[357] She recommended that the Commission direct Consumers to demonstrate in its next rate case that its proposed cost allocation methods satisfy the requirement of MCL 205.54ee(10)(e)(x)(c) that enterprise data centers "not take service under a rate that causes residential customers to subsidize the costs incurred to provide electric service to the facility."[358] She also recommended that the Commission direct 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 disclose the difference in revenue requirements and resource portfolios."[359] On rebuttal, Consumers witness Laura Connolly opposed these recommendations, claiming they are unnecessary.

In Consumers Energy's recently concluded data center tariff case, U-21859, the Commission addressed these issues.[360] The Commission directed Consumers in its next rate case after this one to file at least six cost allocation and rate design proposals concerning data centers

[357] Palmer Direct, 6 Tr 3924-29.

[358] *Id*. at 3927. Quote is from the statute.

[359] Palmer Direct, 6 Tr 3927.

[360] Case No. U-21859, Order, November 6, 2025, pp 114-20.

and directed modeling issues to the IRP planning parameters docket, Case No. U-21867.[361] While MNSC are not entirely satisfied with these outcomes – particularly the second one – the Commission has spoken on these issues for now. MNSC anticipate further engagement in the proceedings identified by the Commission and reserve the right to take further positions on data center issues in the reply brief if any party takes a different position on these issues.

D. The costs of advanced metering infrastructure should be allocated according to its system-wide benefits.

MNSC believe the following is the record on this issue: Direct Testimony of MNSC witness Caroline Palmer, 6 Tr 3911-17, and her sponsored exhibits MEC-15 and MEC-16; Rebuttal Testimony of Company witness Emily Davis, 4 Tr 2648-50; Rebuttal Testimony of ABATE witness Brian Andrews, 6 Tr 3826-29; Rebuttal Testimony of Kroger witness Jared Robertson, 5 Tr 3414-20; Company exhibit A-72; and Cross Examination of Company witness Emily Davis, 4 Tr 2702-2707.

Advanced metering infrastructure – or "AMI" – refers to a network of smart-meters located in individual homes and buildings that collects and communicates customers' energy usage and billing data to electricity providers in real time. In Consumers' service area, advanced meters have already replaced most traditional meters.[362]

Consumers currently classifies the AMI program as strictly "customer-related" and allocates the costs according to the number of customers in each customer class participating in the program.[363] Under that classification – which the Company proposes to continue using – residential customers bear the disproportionate burden of financing AMI, despite evidence that the benefits of the program are system wide. For example, in Consumers' last AMI business case, the

[361] *Id*.

[362] See Davis Rebuttal, 4 Tr 2649; Palmer Direct, 6 Tr 3911 (citing Ex MEC 15, Consumers Response to U21870-MNSC-CE-0221) ("To the extent that customers do not have AMI meters, it is because they have either a) opted out of receiving AMI; or b) are on a rate that makes them ineligible for AMI.")).

[363] Palmer Direct, 6 Tr 3911.

Company reported that of total expected electric smart grid program benefits, demand-related benefits[364] totaled 17%, while energy-related benefits[365] totaled 36%.[366] To ensure that AMI costs are allocated proportionally to the relative benefits of AMI to all customers, MNSC witness Palmer recommends that the Company classify advanced meters as energy, demand, and customer related.[367] Proportional to AMI's benefits, Palmer proposes that the Commission treat AMI meter costs as 36% energy-related, 17% demand-related, and 47% customer-related.[368]

1. Federal and state law requires AMI costs to be allocated according to program benefits, which they currently are not.

On rebuttal, various parties testified to Palmer's proposal, claiming it would violate basic principles of ratemaking. According to ABATE witness Andrews, a "fundamental principle of cost allocation is the concept of cost-causation," and Palmer's proposal conflicts with that principle by allocating costs based on alleged benefits.[369] Kroger witness Robertson claims that by modifying cost-allocation "based on actual and estimated benefits" – as Palmer recommends – the Commission would be departing from cost causation.[370] Federal and state law suggest the opposite, however – by classifying AMI costs as 100 percent customer-related and allocating them without regard to AMI's system-wide benefits, the Company is currently departing from cost-causation principles.

---

[364] Demand-related benefits include: "AC Load Control Avoided Generation, Transmission and Demand Response Avoided Generation, Transmission." Palmer Direct, 6 Tr 3913.

[365] Energy-related benefits include: "Theft Reduction, AMI Induced Conservation & Efficiency Energy, and Demand Response Conserved Energy." Palmer Direct, 6 Tr 3913.

[366] Palmer Direct, 6 Tr 3913.

[367] Palmer Direct, 6 Tr 3911.

[368] Palmer Direct, 6 Tr 3913.

[369] Andrews Rebuttal, 6 Tr 3827-28.

[370] Robertson Rebuttal, 5 Tr 3418.

Michigan law, MCL 460.11, requires the Commission to ensure the establishment of electric rates equal to the cost of providing service to each customer class. The phrase "equal to the cost of providing service to each customer class" refers to the general principle that all approved rates reflect to some degree the costs actually caused by the customer who must pay them (cost-causation).[371] Cost-causation is a well-established principle of federal and state ratemaking which requires customers to receive benefits "roughly commensurate" to their costs.[372] Under the cost-causation principle, customers cannot be forced "to pay for a facility [or program] if they do not receive any benefits from it," but likewise, customers cannot be forced "to pay the entire cost of a facility [or program] that benefits many."[373]

In evaluating compliance with the cost-causation principle, courts have recognized that cost allocation is not an exact science and involves a "myriad of facts" and equitable considerations.[374] In some cases, courts have recognized that equitable considerations – "independent of those inherent in the cost causation principle itself" – may be the controlling factors in cost allocation.[375]

---

[371] See NARUC, *Tariff Development I: The Basic Ratemaking Process*, available at https://pubs.naruc.org/pub.cfm?id=538E730E-2354-D714-51A6-5B621A9534CB (accessed December 3, 2025) (stating that the objective of cost-of-service ratemaking is to apportion the total utility costs among customer classes in a fair and equitable manner – a principle "frequently referred to as cost causation"); see also *Midwest ISO Transmission Owners v FERC*, 373 F3d 1361, 1363 (DC Cir 2004).

[372] See *Paragould Light & Water Comm'n v FERC*, 144 F4th 287, 292 (DC Cir 2025); also *Midwest ISO Transmission Owners*, 373 F3d at 1363 ("Compliance with that unremarkable principle is evaluated by comparing the costs assessed against a party to the burdens imposed or *benefits drawn* by that party.") (emphasis added).

[373] *Paragould Light & Water Comm'n*, 144 F4th at 292; see also *BNP Paribas Energy Trading GP v FERC*, 743 F3d 264, 267-68 (DC Cir 2014) ("The flip side of the [cost-causation] principle is that the Commission generally may not single out a party for the full cost of a project, or even most of it, when the benefits of the project are diffuse.").

[374] E.g., *Colo. Interstate Gas Co. v Fed. Power Com.*, 324 US 581 (1945); see also *Midwest ISO Transmission Owners*, 373 F3d at 1363 ("Reviewing courts have never required a ratemaking agency to allocate costs with exact precision. It is enough…that the cost allocation mechanism not be 'arbitrary or capricious' in light of the burdens imposed or benefits received.").

[375] *BNP Paribas Energy Trading GP*, 743 F3d at 269 (citing *Norwood v FERC*, 962 F2d 20, 24 (DC Cir 1992)).

The Michigan Public Service Commission adheres to these cost causation principles, requiring utility costs to be broadly allocated according to the benefits accrued to each customer class. In Case No. U-10554, for example, the Commission recognized that customers need not be direct participants in a utility program to be allocated some programmatic costs.[376] In that case, the Commission concluded that it was reasonable and just to allocate the costs of the demand-side management (DSM) program to program participants and non-participants alike because "all utility customers will benefit from the reduction in peak demand caused by [the] DSM program."[377] The Commission observed: "Although DSM costs have been allocated to all customers, it does not necessarily follow that all customers benefit equally."[378] In Case No. U-21461, the Commission issued a similar order, rejecting recommendations by the ALJ and various intervenors that distributed energy resource management system (DERMS) implementation costs only "be borne by DER customers" because DER benefits "flow to all customers."[379]

Similarly, the benefits of advanced meters "flow to all customers," regardless of whether the individual customer opts into the AMI program. As discussed in Case No. U-21389, the Company has a continuing obligation to produce information about its AMI program, including information about the "continuous opportunities that the investment in AMI brings to customers and the company, including opportunities for efficiencies and cost savings."[380] Relying on the information filed in past cases, MNSC witness Palmer testified to the broad range of functions

[376] Case No. U-10554, Order, June 19, 1995, pp 20-21.

[377] *Id*.

[378] *Id*.

[379] See Case No. U-21461, Order, July 2, 2024, pp 66-71 (recognizing benefits to all customers, including "resource diversification, reliability improvements, and health and environmental benefits").

[380] Case No. No. U-21389, Order, March 1, 2024, p 299.

served by advanced meters beyond traditional metering.[381] According to her testimony, advanced meters help manage demand, which "in turn provides system capacity benefits, and line loss reduction, which provides a system energy benefit."[382] The Company has also previously acknowledged that its AMI meters – "an essential component of its overall AMI system" – provide benefits, including reduced energy theft, peak demand reduction, and energy consumption savings, which benefit all customers.[383]

In her testimony, witness Palmer also noted examples where public utility commissions in other jurisdictions have allocated the costs of AMI according to its benefits. In 2016, the Maryland Public Service Commission approved a proposal to allocate AMI costs using a combination of customer-based, demand-based, and energy-based allocators.[384] The Maryland Public Service Commission concluded that its "hybrid approach most fairly spreads the costs and related benefits of AMI" amongst customers.[385] The Colorado Public Utilities Commission also applied a hybrid approach to allocate AMI costs, recognizing that "there are system-wide benefits of AMI" that should be reflected in its cost allocation.[386] Like the Michigan Public Service Commission, these

[381] Palmer Direct, 6 Tr 3912-14 ("The Company last filed an AMI business case in Case No. U-21389.").

[382] Palmer Direct, 6 Tr 3912.

[383] Palmer Direct, 6 Tr 3912 (citing Direct Testimony of Company witness David E. Schonhard, Case No. U-15645 (Remand), January 14, 2014, p 12).

[384] Palmer Direct, 6 Tr 3915 (citing In the Matter of the Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (Hereafter, "MD PSC, Case No. 9418"), Order No. 87884, November 15, 2016. (Accessed September 30, 2025) https://www.psc.state.md.us/wp-content/uploads/Order-No.-87884-Case-No.-9418-Pepco-Rate-Case-1.pdf, pp 105-106).

[385] *Id*.; see also Palmer Direct, 6 Tr 3915-16 (noting that the Maryland Public Service Commission continues to use a hybrid approach to allocate the costs of AMI).

[386] Palmer Direct, 6 Tr 3916 (citing Colorado Public Utilities Commission Docket No. 23AL-0243E, February 7, 2024, 2023 CO Phase II Electric Rate Review Decision No. C24-0117, p 23).

other commissions must adhere to cost-causation principles, and they did so when they allocated their own utilities' AMI costs according to its system-wide benefits.

2. Advanced meters are justified by more than their basic metering functions.

Company witness Davis, ABATE witness Andrews, and Kroger witness Robertson criticized Palmer's cost allocation recommendation, claiming the installation and investment in advanced meters is "driven by the need to connect and serve a customer," not by their other benefits.[387] However, when the Company began deploying advanced meters in its service territory nearly 15 years ago,[388] the reason was not to connect customers to Consumers' system because those customers were already connected to Consumers' system via traditional meters.[389] On cross, witness Davis admitted that "customers who were migrated from non-transmitting meters to AMI meters were already connected to Consumers' system."[390] Davis also agreed that Consumers' customers incurred incremental costs when they were transitioned from traditional meters to advanced meters, and with that new cost also came new benefits.[391] The Company has advertised those benefits to customers and the Commission as the reason for scaling up the program from smaller pilot programs.[392]

---

[387] Davis Rebuttal, 4 Tr 2672; 4 Tr 2706; Andrews Rebuttal, p 3 ("[W]hile AMI systems provide some operational benefits, those benefits are incidental and system wide, not direct drivers of metering costs."); Robertson Rebuttal, p 7 ("[T]he customer who needs the meter incurs the meter cost and therefore should pay for it.").

[388] Davis Rebuttal, 4 Tr 2673.

[389] 4 Tr 2705.

[390] *Id*.

[391] 4 Tr 2705-2706.

[392] See Case No. U-15645, Direct Testimony of David E. Schonhard, January 14, 2014, pp 11-12, 19-23.

Nevertheless, Company witness Davis and others emphasize the fact that "the addition of a customer requires a meter" and argue that those customers appropriately bear more of the meter costs. However, under Palmer's proposal, customers receiving AMI will still bear more of the cost burden. After all, Palmer's proposal still calls for nearly half of AMI costs to allocated based on customer-specific treatment.[393]

Lastly, Kroger witness Robertson claimed that the benefits of AMI – including avoided costs associated with energy savings and demand reductions – are hypothetical and therefore cannot be allocated according to a cost-of-service study.[394] However, the Company already quantified the demand and energy benefits of AMI in its business case, which suggests the benefits are material, not hypothetical.[395] In this case, witness Palmer recommends the Company continue updating its AMI business case to ensure that the benefits of AMI continue to be quantified and disclosed.[396]

3. Past reliance on the weighted customer allocator – allocator 170 – to apportion metering costs does not imply that it has been contested and approved by the Commission.

Various parties argued that the Company should continue allocating AMI costs using the existing methodology because the Commission consistently applied that methodology in past cases.[397] The parties' reliance on past practices is misguided. During the 15 years since AMI was

[393] Palmer Direct, 6 Tr 3913.

[394] Robertson Rebuttal, 5 Tr 3419.

[395] See Palmer Direct, 6 Tr 3913.

[396] See Palmer Direct, 6 Tr 3913.

[397] See Andrews Rebuttal, 6 Tr 3827 ("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."); Davis Rebuttal, 4 Tr 2673 ("[T]he Commission has consistently relied on the weighted customer allocator to fairly apportion meter costs amongst customer classes.").

introduced,[398] no party has actually litigated AMI cost allocation, nor has the Commission specifically opined on the issue. There are many legitimate, non-precedential reasons why this issue has not been raised until now. First, since Consumers began rolling out its AMI program, it has taken the Company years to achieve AMI implementation in meaningful numbers. Similarly, it has taken years for the benefits of AMI to grow to current levels. Second, intervenors have limited resources and must prioritize the issues in any given case. The fact that an issue has not been contested in recent cases is not precedential for purposes of barring future consideration.[399] Past practice of classifying AMI costs as 100 percent customer-related and applying Company allocator 170 should not be an obstacle to imposing a more equitable cost allocation in this case.

4. MNSC recommends AMI cost allocation consistent with cost-causation principles and continued disclosure of AMI benefits through the Company's business case.

Consistent with cost-causation principles, witness Palmer strongly encourages the Commission to reevaluate how AMI costs are being allocated. MNSC support Palmer's recommendation to allocate costs in proportion to AMI's system-wide benefits, which would require classifying AMI costs as "36% energy-related, 17% demand-related, and 47% customer-related."[400] Palmer also recommends that the Commission order the Company to continue producing its AMI business case benefit analysis.[401] MNSC support this proposal, which will ensure continued transparency about the impacts of AMI for all customer classes.

---

[398] According to Company witness Davis, Consumers began to "fully deploy electric AMI meters in its service territory nearly 15 years ago." Davis Rebuttal, 4 Tr 2673.

[399] See Case No. U-20527, MEC Initial Brief, October 8, 2022, pp 32-33 (citing *In re Wisconsin Electric Power Company*, Case No. U-12615, Order dated November 20, 2001, 2001 WL 1658750, p 9 (placing little weight on past Commission decisions where it "did not adjudicate disputes or make findings regarding subsidiary issues")).

[400] Palmer Direct, p 9.

[401] *Id*.

VI. RATE DESIGN

A. Large Economic Development Rate.

MNSC believe the following portions of the record are relevant to the issues in this case involving the LED rate: Direct Testimony of Consumers Energy witness Laura Connolly, 3 Tr 159-61; Connolly Rebuttal, 3 Tr 169-72; Connolly Cross, 3 Tr 175-195 and 513-534 (public) and 3 Tr 201-203 (confidential); Ex A-16, Schedules F4.0 and F5 and Ex A-70 (confidential); Direct Testimony of MNSC witness Caroline Palmer, 6 Tr 3930-37 (public) and 4674-81 (confidential); Ex MEC-19, 20, 21, 22, 27, 28, 29C, 30, 31, 34, 35C, 36, and 48; Direct Testimony of ABATE witness James Dauphinais, 6 Tr 3652-55; Dauphinais Rebuttal, 6 Tr 3666-69; and Rebuttal Testimony of Solar Technology witness Michael Gorman, 4 Tr 3172-80.

Consumers Energy has a Large Economic Development (LED) rate that it currently offers to primary customers with a minimum new or expanded demand of 35 MW. The LED rate is heavily discounted in a variety of ways discussed below. The Commission approved the LED rate in an *ex parte* proceeding in 2021.[402] In this case, Consumers seeks approval to offer a facilities allowance to LED customers that would offset the incremental distribution investment cost of adding a new LED customer to the system. The Commission has rejected adding facilities allowances to the LED rate in Case Nos. U-21389 and U-21585, and Consumers has returned in this case seeking approval under modified terms. Consumers also seeks to apply the allowance retroactively to existing LED customers who signed without an allowance.

The Commission should deny approval of the facilities allowance, for several reasons described in detail below. If the Commission does approve the facilities allowance, at a minimum it should not approve retroactive application of it and the Commission should require Consumers to track and true up revenues from the allowance to ensure that LED customers pay all the costs incurred to connect them to Consumers' system.

[402] Case No. U-21160, Order, December 22, 2021.

Irrespective of whether it approves or disapproves the facilities allowance, the Commission should require Consumers to increase the system contribution charge in the LED rate because it is miniscule, not based on the cost of service, and has never been increased since the LED rate was approved *ex parte*. The Commission should require Consumers to shorten the LED rate contract term, which currently can be as long as 20 years, because there is no evidence that Consumers needs to provide such large discounts over such a long period of time to promote economic development.

1. The LED rate provides excessive and unreasonable discounts.

The LED rate is comprised of several charges. The first is a production or capacity charge that is based on the MISO Cost of New Entry (CONE) at the time the LED customer enters a rate contract.[403] The rationale for using the MISO CONE is that it represents the incremental cost of capacity.[404] Consumers' embedded cost of capacity is greater than 100% of CONE.[405] Therefore, LED rate production charges are considerably lower than the production charges for rate GPD, the closest counterpart:

[403] Connolly Cross, 3 Tr 180-81; Ex A-16, Schedule F-5, p 64.

[404] Connolly Cross, 3 Tr 182-83.

[405] *Id*. at 184.

Voltage Level	GPD Rate Production Charges[406]	LED Rate Production Charges[407]
1	$16.611 per kW June-September; $14.64 per kW October-May	$11.27 per kW
2	$16.82 per kW June-September; $14.82 per kW October-May	$11.43 per kW
3	$17.01 per kW June-September; $15.00 per kW October-May	$11.61 per kW

To make matters worse, the LED production charge is fixed for the life of the rate contract, even as the MISO CONE increases over time.[408] As CONE increases over the 15 or 20 years that an LED rate contract is in effect, the difference between the incremental cost of capacity and what the LED customer actually pays for capacity will grow.[409] The difference between GPD production charges, which are based on embedded costs and change in each rate case, and LED production charges that are based on marginal capacity costs when the contract starts and are fixed for 15 to 20 years, will also grow.[410]

[406] Connolly Cross, 3 Tr 186; Ex A-16 Schedule F5, pp 48-49.

[407] Connolly Cross, 3 Tr 186; Ex A-16 Schedule F5, p 64.

[408] *Id*. at 181-82.

[409] *Id*. at 182-83.

[410] *Id*. at 186.

LED customers are also eligible for interruptible service.[411] At 50% interruptible, an LED customer would pay half the already-discounted production charges listed in the table above.[412] At 100% interruptible, an LED customer would pay no production charges at all.[413]

The LED rate also includes a transmission charge. The transmission charge is based on the incremental cost to provide the LED customer with transmission service.[414] As such, it is much lower than the transmission charges for GPD customers, which are based on embedded transmission costs:[415]

Voltage Level	GPD Rate Transmission Charges[416]	LED Rate Transmission Charges[417]
1	$9.17 per kW June-September; $8.53 per kW October-May	$1.59 per kW
2	$9.30 per kW June-September; $8.66 per kW October-May	$1.62 per kW
3	$9.45 per kW June-September; $8.80 per kW October-May	$1.64 per kW

LED customers also pay a system contribution charge.[418] The system contribution charge is characterized as a contribution to embedded production costs, but it is *miniscule* – less than three

[411] Ex A-16, Schedule F5, p 66.

[412] Connolly, Cross, 3 Tr 187.

[413] *Id*.

[414] Connolly Cross, 3 Tr 189.

[415] Connolly Cross, 3 Tr 189; Ex A-16, Schedule F-5, p 63.

[416] Connolly Cross, 3 Tr 189-91; Ex A-16 Schedule F5, pp 48-49.

[417] Connolly Cross, 3 Tr 189-91; Ex A-16 Schedule F5, p 64.

[418] Connolly Cross, 3 Tr 188; Ex A-16, Schedule F-5, p 64.

one-hundredths of one cent per kWh.[419] The system contribution charge is intended to represent one percent of the company's embedded cost of generation.[420] The Commission approved the system contribution charge in 2021 when it approved Consumers' LED rate on an ex parte basis.[421] The charge has never been increased, even though Consumers' embedded cost of generation has gone up since then.[422]

The energy charge for the LED rate is based on the MISO Real-Time or Day-Ahead Locational Marginal Price (LMP).[423] The distribution charge represents rate GPD's share of embedded distribution system costs.[424] Distribution charges are updated from time to time in rate cases.[425]

Overall, Consumers Energy's proposed rates for GPD customers in this case – among the lowest full-service rates the Company offers – range from 6.4 cents per kWh to 9.5 cents per kWh, depending on the customer's voltage level, usage, and the season.[426] By contrast, Consumers' estimated average LED rate is [redacted][427]

For context, Consumers' proposed residential RSP rates in this case for a customer using 650 kWh per month are 23.1 cents per kWh in summer and 20.1 cents per kWh the rest of the year.[428] Residential rates continue to escalate while the Company strives to give ever more

[419] *Id*.

[420] Connolly Cross, 3 Tr 188.

[421] *Id*.

[422] *Id*.

[423] Ex A-16, Schedule F5, p 64.

[424] Connolly Cross, 3 Tr 178-79.

[425] *Id*. at 179.

[426] Connolly Cross, 3 Tr 191-92; Ex A-16, Schedule F-4.0, pp 26, 28, and 30.

[427] Connolly Cross, 3 Tr 201-202 (confidential); Ex A-70 (confidential).

[428] Ex A-16, Schedule F-4.0.

discounts to large customers – even customers who are already signed – under the guise of economic development.

2. The Commission Should Reject Consumers' Proposed LED rate Facilities Allowance.

a. Overview of the facilities allowance for the LED rate.

Consumers witness Connolly explained that the Company seeks approval to offer a facilities allowance for the LED rate.[429] The facilities allowance would reduce an LED customer's incremental distribution charge.[430] The incremental distribution charge collects the costs of dedicated substation, transformers, wires, and metering that Consumers incurs specifically to serve that customer.[431] The Company would set the facilities allowance amount based on the net present value (NPV) of five years' worth of expected distribution and system contribution charge revenues from the LED customer.[432] Consumers would then reduce the LED customer's incremental distribution charge by that amount.[433]

Witness Connolly testifies that the proposal is consistent with the Commission's Order in Case No. U-21585 because the allowance amount is based on five years of distribution and system contribution charge revenues.[434] However, her only comments on why the allowance is needed are that "potential customers have inquired about the availability of a facilities allowance such as that

[429] Connolly Direct, 3 Tr 159.

[430] Palmer Direct, 6 Tr 3930.

[431] Palmer Direct, 6 Tr 3930; Ex MEC-19, Response to MNSC-CE-0253(c); Ex MEC-20, Response to MNSC-CE-0255(c).

[432] Connolly Direct, 3 Tr 159; Palmer Direct, 6 Tr 3930; Ex MEC-19, Response to MNSC-CE-0253 with Attachment 1.

[433] *Id*.

[434] Connolly Direct, 3 Tr 160.

offered under DTE Electric Company's Rate D13" and that adding such an allowance would "better align with other cost-based large customer rate options in Michigan . . ."[435]

b. The Commission has denied prior requests for approval of a facilities allowance for the LED rate for reasons that were in addition to the types and length of revenues included in the allowance calculation.

The Commission has twice adopted PFD recommendations to deny Consumers' request to offer a facilities allowance to LED rate customers, albeit on different terms. In Consumers' 2023-24 electric rate case, U-21389, the Company proposed a facilities allowance that would be calculated using 20 years of both production and distribution revenues. The PFD found:

- "[T]he arguments regarding the proposed facilities allowance creating a subsidy for Rate LED customers" were "persuasive."[436]
- "[I]nstituting such an allowance would operate to place the burden of paying embedded costs on other ratepayers."[437]
- "[T]he details of the facilities allowance proposal have not been delineated sufficiently to justify approval of the proposal."[438]
- "Consumers and ABATE have not shown conclusive evidence that instituting such a facilities allowance would lead to more large manufacturers bringing their facilities to Michigan."[439]
- "[A]pproving the proposed facilities allowance as presented would lead to more embedded costs being borne by other ratepayers for a speculative proposition that more large manufacturers will come to Michigan." [440]

[435] *Id*. at 159.

[436] Case No. U-21389, PFD, December 21, 2023, p 499.

[437] *Id*.

[438] *Id*. at 500.

[439] *Id*.

[440] *Id*.

- The Commission should "deny the proposed facilities allowance. However, should the Commission choose to adopt the proposed facilities allowance, this PFD recommends the Commission adopt Staff's recommendation that Rate LED customers be required to pay the same embedded distribution costs as others and a system contribution charge."[441]

In its Order, the Commission found the PFD's recommendations were "well-reasoned and supported by the record;" and adopted them.[442] The Commission noted that it "will continue to support economic development efforts, including innovative rate offerings, but reminds Consumers that such offerings must reflect COS principles and remain consistent with statutory provisions that prohibit cross-subsidization."[443]

In Case No. U-21585, Consumers again proposed a facilities allowance for the LED rate based on 20 years of both production and distribution revenues. The Company then pivoted in rebuttal to modify the proposal to exclude production revenues from the calculation of the maximum available amount of the facilities allowance. The PFD again recommended that the Commission deny approval of the proposal, both because of the revenues to be used in the calculation and for other reasons, as well:

> This PFD agrees with the Company, ABATE, and Staff that a facilities allowance for Rate LED should only consider distribution and system contribution revenues and not power supply revenues. However, this PFD finds that the Company has not provided sufficient evidence to demonstrate that a facilities allowance for Rate LED is needed or that it would lead to enhanced economic development. Additionally, this PFD agrees with Staff and MNSC that using the entire term (up to 20 years) of a customer's contract to calculate the facilities allowance—as proposed by the Company and supported by ABATE, HSC, and Walmart—would essentially erase any benefit to the system and could result in other customers subsidizing the customer on Rate LED. This PFD finds that if the Company believes it needs to offer a facilities allowance for Rate LED to attract large customers, it should

[441] *Id*.

[442] Case No. U-21389, Order, March 1, 2024, p 248.

[443] *Id*.

> propose a facilities allowance that is based on a limited term, like DTE's Rate D13. Therefore, this PFD recommends that the Commission deny the proposed facilities allowance.[444]

The Commission adopted the PFD's recommendation. The Commission also stated that – should Consumers propose another facilities allowance for LED in the future – it should "include[] only distribution and system contribution revenues, not power supply revenues, and [be] based on a limited term, similar to DTE Electric's Rate D13."[445]

c. The Commission should deny approval of a facilities allowance for the LED rate because Consumers has not demonstrated that such an allowance is just, reasonable, or needed.

The public utilities statutes require the Commission to "ensure the establishment of electric rates equal to the cost of providing service to each customer class . . ."[446] The public utilities statutes also require that "[t]he rates of an electric utility shall be just and reasonable and a consumer shall not be charged more or less than other consumers are charged for like contemporaneous service rendered under similar circumstances and conditions."[447] As the proponent of adding a facilities allowance to the LED rate, Consumers has the burden to demonstrate that its proposal meets these requirements.[448] The Company has not met this burden, for at least five reasons.

[444] Case No. U-21585, PFD, January 27, 2025, pp 574-75.

[445] Case No. U-21585, Order, March 21, 2015, pp 424-25.

[446] MCL 460.11(1).

[447] MCL 460.557(4).

[448] *Dillon v Lapeer State Home & Training School,* 364 Mich 1, 8; 110 NW2d 588 (1961); *BCBSM v Governor,* 422 Mich 1, 88-89; 367 NW2d 1 (1985); *In re Michigan Gas Utilities Co,* MPSC Case No. U-7484, Opinion & Order August 30, 1983, p 10, and *In re Detroit Edison Co,* MPSC Case No. U-8030-R, Opinion & Order, July 9, 1987, pp 16-17.

i. Consumers has not proven that reducing an LED customer's incremental distribution charge through the facilities allowance would not increase costs for other customers.

MNSC witness Caroline Palmer explained that there are two categories of incremental distribution costs necessary to serve an LED rate customer:

(1) The costs of the customer's dedicated distribution infrastructure; and

(2) The marginal cost of adding more demand to the rest of the shared distribution system – such as shared lines, transformers, and substations.[449]

The cost of the dedicated infrastructure is typically recovered through the customer's incremental distribution charge, but the facilities allowance would reduce that charge.[450] Therefore, to prevent cost shifting to other customers, Consumers must demonstrate that the expected future revenues included in the facilities allowance – which include incremental distribution charges and standard distribution charges – cover *both* the costs of the dedicated infrastructure *and* the marginal cost of adding the customer's load onto the rest of the distribution system.[451]

Ms. Palmer noted that while the orders in U-21389 and U-21585 "rightfully narrowed the revenues that could be included in any LEDR facilities allowance for this reason," using expected distribution revenues to calculate the facilities allowance commits all the revenues meant to cover both the costs of dedicated distribution infrastructure and the marginal costs of adding more load to the system to pay for the customer's dedicated facilities costs.[452] Currently, Consumers cannot ensure that theses charges cover both categories of costs because the Company has not calculated

[449] Palmer Direct, 6 Tr 3931.

[450] *Id*.

[451] *Id*. at 3931-32.

[452] *Id*. at 3932.

its marginal distribution costs.[453] Because Consumers has not proven that its facilities allowance will not shift some of the LED customer's incremental distribution costs to other customers, Ms. Palmer recommended that the Commission disapprove the proposal.

On rebuttal, Consumers witness Connolly asserted that LED rate distribution charges are based on embedded distribution system costs, and that "other similarly situated customers are afforded a Contribution in Aid of Construction ("CIAC") allowance to cover some or all of the incremental costs of the distribution facilities to serve them" without having to demonstrate that they are covering their marginal distribution costs with the CIAC allowance.[454] Therefore, she concludes, requiring Consumers to demonstrate that LED customers would still cover their marginal distribution costs with a facilities allowance "is flawed and not consistent with the methodology approved by the Commission in approving the LEDR."[455]

However, when asked for the source of her position that ensuring LED customers pay their marginal distribution costs is inconsistent with the Commission's methodology in approving the LED rate, Ms. Connolly cited the Order in U-21585 for its lack of reference to "proof of marginal distribution cost coverage."[456] But the Order in U-21585 did not approve the LED rate, nor did it approve a facilities allowance for the LED rate.

Further, Ms. Connolly's assertion that it would be unfair to ensure that LED customers cover their marginal distribution costs before giving them a facilities allowance when the same is not required for GPD customers to receive a CIAC allowance is unfounded because LED customers are plainly not "similarly situated" to GPD customers. As discussed above, GPD

[453] Palmer Direct, 6 Tr 3932; Ex MEC-21, Response to MNSC-CE-0256, sub-part (g).

[454] Connolly Rebuttal, 3 Tr 169.

[455] *Id*.

[456] Ex MEC-27, MNSC-CE-0764.

customers do not receive the deep discounts on their production and transmission charges that LED customers receive, nor are GPD customers' production charges fixed at the time they sign a contract for 15 to 20 years even while the underlying capacity costs increase – as is the case for LED customers. Because GPD customers contribute to embedded capacity and transmission costs, a case can be made that other ratepayers get something in return for fronting the cost of new GPD customers' dedicated infrastructure.[457] No such case can be made for LED customers.

ABATE witness James Dauphinais argues that Ms. Palmer "provided no evidence to support her contention there would be a marginal distribution cost for Consumers to serve a Rate LED customer beyond the cost of dedicated facilities" – or that the remaining distribution charges would not cover such a cost if there was one.[458] Mr. Dauphinais either misapprehends or mischaracterizes the burden of proof, however. Consumers and ABATE are seeking approval of the facilities allowance, and they must demonstrate that rates with the 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.[459] When the burden of proving a fact falls on one party, the other party does not have the burden of proving the opposite fact.[460] MNSC and Ms. Palmer do not have the burden to prove that such an allowance would not be just and reasonable or that it would not ensure rates are equal to the cost of service.

[457] Not enough of a case, but that is an argument for another day.

[458] Dauphinais Rebuttal, 6 Tr 3667.

[459] MCL 460.11(1); MCL 460.557(4).

[460] *S C Gary, Inc v Ford Motor Co,* 92 Mich App 789, 803-804; 286 NW 2d 34 (1979).

To be eligible for the LED rate, a customer must have new or expanded incremental demand of at least 35,000 kW, or 35 MW.[461] While data centers have recently distorted conventional notions of scale, 35 MW is a very large customer. 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. Certainly Mr. Dauphinais provides no evidence to support his bare assertion. And, as noted above, Consumers has not evaluated marginal distribution costs at all.

Mr. Dauphinais also claims that the system contribution charge "is another source of sales margins from the customer that would not exist but for the customer taking service from Consumers."[462] As explained above, however, the system contribution charge is miniscule and covers less than 1% of Consumers' embedded generation costs. It can hardly be counted on to protect other customers against subsidizing marginal distribution costs caused by a new LED customer if a facilities allowance takes up a large share of the customer's distribution charges.

Solar Technology witness Michael Gorman argues that "Consumers is able to adjust the distribution charge listed in LEDR if the Rate GPD distribution charge is not sufficient for Consumers to recover its incremental distribution or connection costs incurred to serve the LEDR customer."[463] There are two problems with that argument. First, as noted above, the proposed tariff language for the facilities allowance contains no specifics that would require Consumers to adjust the facilities allowance or resulting distribution charges to cover marginal distribution costs. Second, as also noted above, Consumers has not evaluated and does not know what those marginal

[461] Consumers Rate Book, First Revised Sheet No. D-78.10.

[462] Dauphinais Rebuttal, 6 Tr 3667.

[463] Gorman Rebuttal, 4 Tr 3174.

distribution costs are. Given these facts, Mr. Gorman's argument about what Consumers *could do* comes across as wishful thinking.

Mr. Gorman also claims that Consumers has the right under Rule C1.4 of its tariff, "Extraordinary Facility Requirements and Charges," to levy an extraordinary facilities charge to an LED customer to recover incremental costs of connecting the customer that exceed the facilities allowance.[464] However, nothing in the LED tariff says that. The LED tariff only says that "Customers taking service under the Large Economic Development Rate are ineligible for the terms of the Contribution in Aid of Construction Allowance Schedule located in Rule C1.4, Extraordinary Facility Requirements and Charges."[465] And Rule C1.4 does not reference the LED tariff or LED customers.

Mr. Gorman also claims that an LED customer will "likely" not use shared distribution infrastructure, and if it does use such infrastructure, the customer's load will not cause any additional costs as a result of the additional demand on that infrastructure.[466] However, he again cites no evidence to support this bare assertion.

[464] Gorman Rebuttal, 4 Tr 3174-76, citing Rule C1.4, Extraordinary Facility Requirements and Charges.

[465] Consumers Rate Book, First Revised Sheet No. D-78.10.

[466] Gorman Rebuttal, 4 Tr 3177-78.

ii. Even if the distribution charges did cover both the costs of dedicated distribution infrastructure and the marginal cost of adding more demand to the distribution system, there is significant risk that the LED customer will not cover all these costs through its distribution charges over the term of their contract.

That is because Consumers' LED tariff and rate contracts expressly relieve LED customers of paying the full cost of the incremental distribution and transmission investments made to connect them if they leave before the end of their contract term:

> If the customer ceases operation before completion of the contract term, the customer shall pay the remaining balance for any transmission and distribution system investments specified in the contract to provide service to the customer according to the following schedule:
>
> | | |
> |---|---|
> | Up to 50% of the contract term | 100% |
> | More than 50 to 60% of the contract term | 83% |
> | More than 60 to 70% of the contract term | 67% |
> | More than 70 to 80% of the contract term | 50% |
> | More than 80 to 90% of the contract term | 33% |
> | More than 90% to 99.9% of the contract term | 17% |

[467]

Consumers witness Connolly agreed that this schedule means an LED customer who terminates service after the halfway point of its rate contract is relieved of responsibility to pay for a portion of the remaining balance of the costs Consumers incurred to connect them.[468] While she was not certain, she believed that the difference between what the customer owed and paid in that scenario would be made up by other customers in general rates.[469] Since the facilities allowance is provided as a discount to the distribution charge that is levied to recover these investments over the 15- to 20-year life of the LED rate contract, approving the facilities allowance without

[467] Consumers Rate Book, First Revised Sheet No. D-78.10. See also, Ex MEC-29C, pp 4-5, section 11; p 15, exhibit D; pp 19-20, section 11; and p 28, exhibit D.

[468] Connolly Cross, 3 Tr 531-33.

[469] *Id.* at 532-33.

addressing this exposure will only increase the potential size of the stranded costs that could be imposed on other customers.

iii. LED rates already include excessive and unreasonable discounts, and there is no reason to provide these customers with a facilities allowance too.

As discussed above, LED customers already receive excessive and unreasonable discounts. Their production charges are set at the MISO CONE, which is lower than the embedded cost of Consumers' generation capacity that other customers pay. Not only that, their production charges are fixed for the 15- or 20-year life of their contracts, which causes the gap between what they pay and the actual incremental cost of capacity to widen as CONE goes up but their charges stay the same. If they elect interruptible service, they get a further discount on their production charges, up to 100% depending on the level of service elected as interruptible. Their system contribution charge is miniscule and covers less than 1% of Consumers' embedded generation cost. Their transmission charges are less than 20% of what other primary customers pay. Their overall rates are substantially lower than GPD customers.

With LED customers already receiving such extraordinarily discounted rates, no party in this case has explained why these customers need yet another discount in the form of a facilities allowance.

iv. Despite the proposal being rejected as insufficiently developed in Case No. U-21389, Consumers has not developed it materially further in this case.

As also discussed above, one of the findings of the ALJ adopted by the Commission in Case No. U-21389 was that the details of the facilities allowance had not been delineated sufficiently to justify approval of the proposal. Yet Consumers has not delineated those details any

further in this case. The proposed tariff change provides no specifics to govern the proposed facilities allowance. The entire change is the addition of three words to a sentence in the LED tariff about distribution charges: "The monthly charge per kW of Maximum Demand per calendar month may be adjusted to contribute to the recovery of the annual revenue requirement associated with investments made by the Company for incremental distribution facilities required to serve the customer and *a facilities allowance* specified in the contract for electric service."[470] The contracts for electric service that will specify the terms of the allowance are not filed with or approved by the Commission.[471]

v. Consumers did almost nothing to support its claim of economic development benefits from a facilities allowance for the LED rate.

Another PFD finding in Case No. U-21389 adopted by the Commission was that Consumers had not supported its claim that a facilities allowance would promote economic development in the Company's service territory. Yet in this case, Consumers submitted almost no evidence at all as to how the rest of its customers would benefit from the Company offering a facilities allowance to LED customers – via economic development or otherwise. And two customers have signed LED rate contracts without a facilities allowance even though they wanted one. The details of those contracts are discussed in the section on retroactive application of the allowance, below.

. . .

[470] Ex A-16, Schedule F-5, p 65.

[471] Connolly Cross, 3 Tr 515.

For all the reasons just discussed, Consumers' proposal should be rejected again. The Company has not demonstrated that it will not shift costs to other customers or that it is necessary.

3. If the Commission approves the LED rate facilities allowance, it should not authorize Consumers to apply it retroactively to existing customers.

If the Commission approves the facilities allowance, Consumers plans to apply it retroactively to two customers who already signed LED rate contracts in 2023 and early 2024.[472] Consumers did not identify this plan in its direct case but disclosed it in discovery: "The Company believes the facilities allowance should apply to existing Rate LED customers if approved. The applicable facilities allowance would be calculated and applied to the existing customer's incremental facilities charge."[473]

MNSC witness Palmer testified that it would not be reasonable to apply the facilities allowance to existing LEDR customers because "[t]he Commission approved Rate LED to attract new load – and the associated investment and jobs – to the state."[474] The LED rate and its excessive discounts already succeeded in attracting the two customers to Michigan without a facilities allowance.[475] And Consumers has not demonstrated that the facilities allowance is necessary to retain them.[476] "Instead, these customers would likely be free-riders" – receiving yet another discount even though the discount is not necessary to induce them to locate here.[477]

---

[472] Connolly Cross, 3 Tr 519. The two customers' confidential LED rate contracts were admitted as Ex MEC-29C.

[473] Ex MEC-22, disc resp MNSC-CE-0257(d).

[474] Palmer Direct, 6 Tr 3933.

[475] *Id*.

[476] *Id*.

[477] *Id*.

What is more, offering a facilities allowance to these two free riders would increase costs for other customers. Using Consumers' test year forecast for Rate LED capacity and energy, Ms. Palmer calculated that Consumers' proposed facilities allowance for the two existing customers would be [redacted] which Consumers would collect in rates from the rest of its customers rather than in distribution charges from the two existing LED customers.[478] No party disputed this calculation of what giving the two free riders a facilities allowance will cost other customers.

In rebuttal, Consumers witness Connolly said that "part of the negotiation with these customers was around potential for a future facilities allowance" and their rate contracts "contained language expressing the Company's intention to file a request to amend this rate to allow LEDR customers to qualify for a CIAC credit."[479] She said "[t]hese customers considered this language and potential for an allowance as part of their decision to locate in the Company's service territory;" and so if the Commission approves the facilities allowance, "it should be applied to customers with express language in their contract around the potential for an allowance."[480]

The actual contract language for these two customers regarding a facilities allowance is not compelling evidence in favor of providing them with an allowance retroactively. The first contract is from 2023 and states that "Consumers shall file with the MPSC an application to amend Rate LED to allow for Rate LED customers to qualify for the Contribution in Aid of Construction credit."[481] Consumers fully performed on this obligation when it filed Case No. U-21389 in May of 2023.[482] Nothing in the contract says that Consumers must provide a facilities allowance to the

[478] Palmer Direct, 6 Tr 3934 (public) and 4678 (confidential).

[479] Connolly Rebuttal, 3 Tr 170.

[480] *Id*.

[481] Connolly Cross, 3 Tr 524, referencing Ex MEC-29C, p 4, section 9.j. Permission to discuss on the public record is at 3 Tr 523.

[482] Connolly Cross, 3 Tr 525.

customer if the Commission did approve it.[483] Nor does the contract say Consumers must continue seeking approval of a facilities allowance if the Commission does not approve it – as happened in U-21389 and the following rate case, U-21585.[484] The same things are true of the contract for the other LED customer.[485]

Michael Gorman, witness for Solar Technology (one of the two existing customers) reiterated his argument that an LED customer with a facilities allowance will nonetheless pay all costs necessary to connect it through distribution charges.[486] This brief explained the lack of evidence to support Mr. Gorman's claim in the discussion of marginal distribution costs, above.

Mr. Gorman also testified: "It is possible that during the term of the LEDR contract the LEDR customer could have opportunities for load growth that would necessitate further distribution investment. The existing LEDR customer should be able to utilize the FA to help facilitate the incremental investment."[487] But then he contradicted himself and said that the facilities allowance should not be limited to incremental load growth because "every other primary customer has an opportunity to utilize an FA."[488]

Just because other (non-LED) primary customers are eligible for a facilities allowance does not mean LED customers – existing or new – should be eligible for it. As discussed earlier in this brief, LED customers already receive excessive discounts on their production and transmission costs compared to GPD customers, which result in substantially lower rates for LED customers.

---

[483] *Id*.

[484] *Id*.

[485] Connolly Cross, 3 Tr 526-27, referencing Ex MEC-29C, p 19, section 9.j.

[486] Gorman Rebuttal, 4 Tr 3179.

[487] *Id*.

[488] *Id*.

There is no equitable or cost-of-service-based reason why LED customers should be entitled to all those discounts and a facilities allowance too. The Commission should not approve the facilities allowance, but if it does, the Commission should at the very least not approve providing it to customers who already signed up for LED service two or three years ago.

4. If the Commission approves the LED rate facilities allowance, it should require Consumers to true up projected and actual revenues and charge the LED rate customer for any revenue shortfall.

Ms. Palmer also testified that it does not appear Consumers plans to true up the facilities allowance if the Company initially overestimates an LED customer's expected revenues, resulting in a shortfall.[489] She recommended that if the Commission approves a facilities allowance, it should require Consumers to reconcile any overestimated revenue upon which it originally based the allowance after five years and recalculate the customer's incremental distribution charges to make up the shortfall.[490]

In rebuttal, Company witness Connolly testified that the LED tariff states the distribution charge "may be adjusted to contribute to the recovery of the annual revenue requirement associated with investments made by the Company for incremental distribution facilities."[491] She said that Consumers "intends to reconcile any differences in actual collections to proposed collections and would include the facilities allowance in those calculations."[492] When asked for more specifics in discovery, Ms. Connolly responded:

> While the contract does not specify a reconciliation cadence, the Company intends to do a periodic review of actual collections to proposed collections for each Rate

[489] Palmer Direct, 6 Tr 3934.

[490] *Id*. at 3934-35.

[491] Connolly Rebuttal, 3 Tr

[492] *Id*.

> LED customer. The Company will recalculate a go forward incremental distribution charge based on actual collections at the time of the review. The new incremental distribution charge will be updated through an amendment to the customer rate contract. At the end of the contract, the Company will do a final reconciliation of actual collections to expected calculations.[493]

Neither ABATE nor Solar Technology submitted rebuttal on this issue. Thus, it appears that if a facilities allowance is approved, Consumers and MNSC do not disagree on the need for a true-up. However, given the somewhat vague nature of Consumers' plans, MNSC submit that the Commission should adopt Ms. Palmer's specific recommendation of a five-year true-up of overestimated revenues and an increase in distribution charges to make up the shortfall, if the Commission approves the allowance.

5. Irrespective of whether it approves or disapproves the facilities allowance, the Commission should require Consumers to increase the LED rate system contribution charge because it is not based on the cost of service.

As noted above, rates must be "just and reasonable" and "equal to the cost of providing service to each customer class"[494] The system contribution charge is neither. As noted above, the purpose of the system contribution charge is ostensibly intended to contribute to embedded production costs. However, it is less than $^{3}/_{100}$ of one cent per kWh and represented only 1% of embedded production costs in 2021 when it was approved in an *ex parte* filing.[495] It has never been increased, and it is locked in for the 15-to-20-year life of an LED rate contract.[496]

[493] Ex MEC-30, disc resp MNSC-CE-0766.

[494] MCL 460.557(4) and 460.11(1).

[495] Connolly Cross, 3 Tr 188.

[496] *Id*.

MNSC witness Palmer testified that Consumers did not base the system contribution charge on any analytical justification.[497] She cited Consumers' witness Hubert Miller's testimony in Case No. U-21224, which acknowledged that the charge was based on what Consumers thought would be competitive with economic development rates in other states.[498] That is not a cost-of-service basis on which to set a charge. Further, because the entire LED rate was approved *ex parte*, the Commission never adjudicated whether it was just and reasonable and based on the cost of providing service. Plainly it is not.

Other aspects of the LED rate have been reviewed and modified in subsequent rate cases. The production, transmission, and distribution charges are updated in each rate case. More options have been added for the energy charge.[499] A maximum contract length was added.[500] Other changes – including the facilities allowance, lowering the minimum demand threshold, and adding a proxy plant option for production and energy charges – have been proposed but not adopted.[501] Yet the "remarkably small"[502] system contribution charge has never been revisited. Ms. Palmer concluded that "Consumers has not presented a cost basis for setting its system contribution charge at 1% of the Rate GPD embedded capacity costs;" and recommended that the Company "raise the charge in order to contribute more meaningfully to embedded system costs."[503]

In rebuttal, Consumers witness Connolly did not try to defend the tiny size of the system contribution charge or argue that it is based on cost of service. She criticized Ms. Palmer for not

[497] Palmer Direct, 6 Tr 3935.

[498] *Id*., citing Cross examination of Consumers Energy witness Hubert Miller in Case No. U-21224, 3 Tr 635-637.

[499] Case No. U-21389, Order, March 1, 2024, pp. 249-50.

[500] *Id*. at 252-53.

[501] *Id*. at 241-52.

[502] Palmer Direct, 6 Tr 3936.

[503] *Id*.

providing "an alternative solution other than to increase it."[504] She also said that the charge is included in existing LED rate contracts for the term of the contract.[505] Finally, Ms. Connolly recommended that if the Commission does direct Consumers to change the system contribution charge, it should be updated consistent with the methodology used to develop the charge in Case No. U-21160.[506]

That can certainly be done. Consumers stated in discovery in this case: "The System Contribution charge was established in Case No. U-21160 and was set based on 1% of the Rate GPD embedded capacity costs."[507] In that case, Consumers took total on-peak capacity revenues based on the capacity charges for Rate GPD Voltage Level 1 from Case No. U-20697, multiplied by 1%, and then divided that revenue by expected energy consumption for a hypothetical customer with 100 MW of demand and a 90% load factor, to establish a system contribution charge of $0.0002838 per kWh – or less than 3 cents per MWh.[508] Updating the capacity revenues for a Rate GPD Voltage Level 1 customer to the capacity charges proposed in this case and performing the same calculation at 25% of embedded costs instead of 1% produces a system contribution charge of $0.0058208 per kWh, or about 0.6 cents per kWh. That charge modestly narrows but does not close the gap between the average LED rate and GPD rates discussed earlier in this brief. MNSC recommend that the system contribution charge be increased to 25% of embedded costs. MNSC further recommend that this charge be updated in each case based on actual costs rather than locked in for the duration of an LED customer's rate contract.

---

[504] Connolly Rebuttal, 3 Tr 171.

[505] *Id*.

[506] *Id*.

[507] Ex MEC-31, disc resp MNSC-CE-0767(d).

[508] Attachment LEDR System Contribution Charge.xlsx to disc resp MNSC-CE-0767(d) (attachment not submitted for admission into evidence).

6. Irrespective of whether it approves or disapproves the facilities allowance, the Commission should require Consumers to shorten the LED rate discount period.

MNSC witness Palmer also testified that LED rate contracts are too long, at 15 to 20 years.[509] Consumers has not justified why it is necessary to provide such substantial rate discounts for such a long time in order to incent economic development – compared with a more reasonable term.[510] Other jurisdictions offer economic development discount rates for five years, including LGE and KU in Kentucky, Dominion in Virginia, Evergy in Missouri and Kansas, Florida Power and Light, and Interstate Power and Light in Iowa.[511] Dominion in South Carolina offers a discount for five years, but requires the customer to remain on the system for 10 years or pay back a portion of credits received.[512] Indiana Michigan Power provides an economic discount rate to Indiana customers for seven years.[513] Based on these examples, and in the absence of justification for 15- to 20-year LED discounts, Ms. Palmer recommended that the Commission limit Consumers to offering rate LED for a maximum of seven years.[514]

On rebuttal, Consumers witness Connolly claimed that "[t]here is no discount associated with LEDR; it is based on cost of service" – citing cursory approval language in the Commission's Order in Case No. U-21160.[515] But obviously the LED rate is an extremely discounted rate – MNSC refers the reader to the detailed comparison of the LED and GPD rates earlier in this brief.

---

[509] Palmer Direct, 6 Tr 4680-81.

[510] *Id*.

[511] *Id*., with detailed references cited therein.

[512] *Id*.

[513] *Id*.

[514] *Id*.

[515] Connolly Rebuttal, 3 Tr 171.

Ms. Connolly also predicted that shortening the contract length "could result in potential stranded assets should a customer decide to cease taking service from the Company at the end of their contract term."[516] However, it is unclear why the distribution charges could not be scaled to the contract length to prevent that from happening. Further, as noted above, the LED rate contracts already allow the LED customer to strand assets by reducing their payment obligation below the remaining balance of transmission and distribution investments made to connect them starting at the halfway mark of their contract term and stepping down from there.[517]

ABATE witness Dauphinais asserts that MNSC proposes to "dramatically lower the maximum allowed term for Rate LED from 20 years to seven years" – but he never justifies why the term should ever have been 20 years in the first place.[518] He also claims that LEDR customers "in many cases, might not have come to the Consumers service territory, or expanded their operations in the Consumers service territory, but for the availability of Rate LED and its allowed term of up to 20 years."[519] Again, however, he provides no evidence to support his claim that such customers would not be sufficiently induced by a discounted rate contract of 5, 7, or 10 years.

Mr. Dauphinais also wrongly claims that "only production charges under Rate LED are not at fully embedded costs," and that transmission charges "are not being discounted versus what other customers pay."[520] As discussed above, however, Consumers witness Connolly confirmed that LEDR transmission charges are based on the incremental cost to provide the LED customer

[516] Connolly Rebuttal, 3 Tr 171.

[517] Consumers Rate Book, First Revised Sheet No. D-78.10. See also, Ex MEC-29C, pp 4-5, section 11; p 15, exhibit D; pp 19-20, section 11; and p 28, exhibit D.

[518] Dauphinais Rebuttal, 6 Tr 3668-69.

[519] *Id*. at 3669.

[520] *Id*. at 3668-69.

with transmission service, and are much lower than the transmission charges for GPD customers, which are based on embedded transmission costs.[521]

Finally, Mr. Dauphinais wrongly claims that "even though the production charges under Rate LED are not based on Consumers' fully embedded costs for production, they are designed to fully cover Consumers' incremental fixed production costs and incremental variable production costs to serve Rate LED customers;" and that this "ensures Consumers' other customers are not subsidizing the production costs Consumers needs to incur to serve Rate LED customers . . ."[522]

As also discussed above, however, Ms. Connolly confirmed that production charges are fixed for the life of the LED contract at the MISO CONE price that was in effect when the contract was signed.[523] The gap between this fixed production charge and the actual incremental cost of capacity only grows as MISO CONE increases for the 20-year period provided in by these unreasonably long contracts.[524] As CONE increases over the 15 or 20 years that an LED rate contract is in effect, the difference between the incremental cost of capacity and what the LEDR customer actually pays for capacity will grow.[525] Therefore, LED customers do not even pay for the incremental cost of capacity to serve them for the full term of their unreasonably long contracts. Ms. Palmer is right that the Commission should direct Consumers to reduce the term of these agreements to seven years.

[521] Connolly Cross, 3 Tr 189; Ex A-16, Schedule F-5, p 63.

[522] *Id*. at 3669.

[523] Connolly Cross, 3 Tr 181-83.

[524] Connolly Cross, 3 Tr 181-82.

[525] *Id*. at 182-83.

B. Investment Recovery Mechanism (IRM) – The Commission should adopt the recommendation of ABATE witness James Dauphinais to reduce Consumers' proposed annual authorized capital expenditure for LVD Lines Reliability by at least $108.8 million per year.

MNSC believes the following is the record on this issue: Direct Testimony of Company witness Heidi J. Myers, 3 Tr 1828-31, and her sponsored exhibit A-163 (HJM-1); Rebuttal Testimony of Company witness Heidi J. Myers, 3 Tr 1842-46; Direct Testimony of Staff witness Nicholas M. Evans, 6 Tr 4448-53; and Direct Testimony of ABATE witness James R. Dauphinais, 6 Tr 3645-50 and his sponsored exhibit AB-1.

Company witness Heidi Myers testified in support of the Company's proposal to continue using its Distribution Investment Recovery Mechanism (IRM), which the Commission approved through February 29, 2026, in Consumers' last rate case, Case No. U-21585.[526] The Company proposes a two-year extension of the IRM beginning May 1, 2026, and ending April 30, 2027, with an increase over the Year 2 spending levels approved in Case No. U-21585 of $266 million in each of Years 3 and 4.[527]

MNSC shares the concerns expressed by ABATE witness James Dauphinais, who recognized that, while there is "conceptual merit" for a Distribution IRM "to meet an urgent and undisputed need," "great care should be taken to ensure" that such a need exists, that any proposed investment "has been robustly shown to be the most cost-effective way to address the need," that authorization extends no longer than necessary, and that spending categories are not defined too broadly.[528] In particular, Mr. Dauphinais expressed concern with Consumers' "very aggressive proposal to approximately quadruple the level of authorized annual capital expenditures proposed in the LVD Line Reliability costs category."[529] Accordingly, Mr. Dauphinais recommended that

[526] Myers Direct, 3 Tr 1828.

[527] *Id.* at 3 Tr 1828-29; Dauphinais Direct, 6 Tr 3947.

[528] *Id.* at 3947-48.

[529] *Id.* at 3948.

the Commission, "as a minimum, reduce Consumers' proposed annual authorized capital expenditure amount of $276.2 million per year for the LVD Lines Reliability cost category for Year 3 (twelve months ending April 30, 2027) and Year 4 (twelve months ending April 30, 2028) of Consumers' Distribution IRM by at least $108.8 million per year," which "would reduce the total annual authorized capital expenditures under Consumers' Distribution IRM for Years 3 and 4 to no more than $243.6 million per year."[530] MNSC supports this recommendation and asks that the Commission adopt it.

C. The Commission should instruct Consumers to develop a proposal for an electric heating or heat pump rate for presentation in its next rate case.

MNSC believes the record in this case consists of: Direct Testimony of MEC-NRDC witness Scott Reeves, 6 Tr 3839-3876, and his sponsored exhibits MEC-1 to MEC-3; and Direct Testimony of Company witness Laura M. Connolly, 3 Tr 174.

MEC-NRDC witness Scott Reeves testified in support of a recommendation that the Commission instruct Consumers to develop a proposal for an electric heating or heat pump rate for presentation its next rate case. Electrification is a key strategy for reducing greenhouse gas emissions to achieve state climate goals, but current rate structures discourage it.[531] Developing rates that support electrification would benefit all customers, not just those who electrify, for the reasons Mr. Reeves explained in detail in his testimony.

Currently, customers who electrify their heating pay much more than the cost to serve any added load.[532] As Mr. Reeves explained, "[e]nergy rates are typically designed to recover fixed system costs, which occur independent of usage, and on-peak system costs, which primarily occur

[530] *Id.* at 3950.

[531] Direct Testimony of Scott Reeves, 6 Tr 3844.

[532] *Id.* at 3845.

in summer."[533] Under Consumers' default residential rate, Summer On-Peak Basic Rate RSP, the costs of electric heating customers' added heating load are recovered largely through volumetric pricing. While heating with electricity may be cheaper than heating with propane and oil, it is generally more expensive than heating with natural gas.[534] It also results in increased winter electric bills irrespective of whether electricity is cheaper or more expensive than other commodity types.[535] Meanwhile, these electric heating customers generate more revenue during the winter season when their usage does not contribute to summer peaks.[536] The combined effect of increased electricity bills and overpayment of fixed costs compared to customers who do not electrify discourages electrification, but better rate design can resolve both issues.[537] After discussing the distinctions between electric heating, heat pump, and technology-specific rates, Mr. Reeves explained that Consumers could adopt either an electric heating (EH) rate or a technology-specific rate such as a heat pump (HP) rate.[538]

Mr. Reeves provided two main reasons why Consumers should develop an EH/HP rate now. *First*, heating electrification is necessary to achieve Michigan's climate goals. While Michigan has not adopted specific building electrification targets, achieving its decarbonization targets will require a significant amount of building electrification.[539] Mr. Reeves reviewed Michigan's climate policy in detail, noting that the MI Healthy Climate Plan indicates that 17% of

[533] *Id.* at 3845-46.

[534] *Id.* at 3845.

[535] *Id.*

[536] *Id.* at 3845.

[537] *Id.* at 3846.

[538] *Id.* at 3849-50.

[539] *Id.* at 3846-47, 3850.

emissions reduction to meet the state's 2030 target should come through buildings.[540] Mr. Reeves also noted that "draft results from a recent Michigan electrification study shows significant potential for heat pump electrification."[541] Currently, over 76% of Consumers' residential customers use natural gas as their primary heating fuel.[542] While incentives exist to reduce the upfront costs of installing heat pumps, the increased operational costs of heat pumps in the form of higher electric bills remains a barrier.[543] An EH/HP rate would encourage electrification by reducing the operational costs of installing heat pumps.[544]

Second, an EH/HP rate would reduce the extent to which heat pump adopters overpay for their share of fixed system costs. Rates are generally set to charge customers the same or similar amounts on a per-unit basis year-round "despite higher electric system costs occurring during season-specific peak periods and a significant portion of fixed system costs being independent of usage."[545] "Since Consumers is summer peaking, a significant portion of system costs are associated with meeting summer peak load; the remaining are independent of or not marginal to usage."[546] Heat pump adopters will generally increase their energy consumption in winter while potentially decreasing it in summer due to increased cooling efficiency.[547] These higher winter

[540] *Id.* at 3860-61.

[541] *Id.* at 3861.

[542] *Id.* at 3750.

[543] *Id.*

[544] *Id.*

[545] *Id.* at 3851.

[546] *Id.*

[547] *Id.*

bills result in Consumers recovering much more from heat pump adopters than it needs to cover the costs of serving their added winter load.[548] An EH/HP rate would remedy this issue.[549]

Mr. Reeves noted that Consumers had a residential space heating rate in effect from 1963 through 2008, when the Commission approved a noncontroversial proposal to terminate it.[550] The historical rationale for the rate had been to compete for residential heating loads, but Consumers concluded that a "rate design that better reflects temporal cost spreads (seasonality) would be far simpler and more equitable."[551] Mr. Reeves then reviewed Consumers' current residential rate offerings and found that none are an adequate substitute for an EH/HP rate.[552] Mr. Reeves also observed that Consumers has implemented some limited initiatives that indirectly support building electrification through its energy waste reduction (EWR) programming, but none that are directly aimed at it.[553]

Mr. Reeves reviewed core ratemaking principles, including sufficiency, fairness, efficiency, customer acceptance, and bill stability, as well as practical challenges to designing rates that reflect those principles.[554] Mr. Reeves then discussed how these challenges will change as more residential customers electrify their space heating over time. In particular, Consumers will see a growing segment of its residential class paying a larger portion of fixed system costs, "effectively

[548] *Id.*

[549] *Id.*

[550] *Id.* at 3853-54 (quoting Case No. U-15245, Order, June 10, 2008, p 68).

[551] *Id.* (quoting Ex MEC-2, Consumers' Response to Discovery Request MNSC-CE-0315; Case No. U-15245, Direct Testimony of Hubert W. Miller, III, 10 Tr 1436).

[552] *Id.* at 3854.

[553] *Id.* at 3859-60.

[554] *Id.* at 3863-65.

subsidizing energy costs for non-participants within the residential customer class."[555] This not only violates the principle of cost causation – i.e., costs should be borne by the customers that cause them to occur; it "fails to account for the value in heat pump adoption and in how building electrification reflects state policy priorities."[556]

A well-designed EH/HP rate would better reflect core ratemaking principles while aligning with state climate policy. Mr. Reeves recommended that Consumers work with Commission Staff and stakeholders to develop such a rate. Mr. Reeves presented several rate elements that should be considered, including eligibility, verification, seasonal definitions (e.g., is winter October through May or November through April?), participation duration requirements to discourage gaming, enrollment design (e.g., opt-in versus opt-out), and pricing design.[557]

Mr. Reeves presented options for rate design that would have different effects on customers who do not electrify depending on the outcomes Consumers might wish to achieve. In one scenario, a rate could be designed that is revenue neutral for the Company and reduces bills for heat pump adopters by setting the rate close to the marginal cost imposed on the grid in winter.[558] For example, if the standard rate is $0.17/kWh and the winter marginal cost is $0.05/kWh, the EH/HP rate could be $0.05/kWh (or close to it) to eliminate as much of the $0.12/kWh overpayment as practicable. In another scenario, a rate could be designed that is still revenue neutral but provides shared benefits to both customers who electrify and those who do not by providing a partial discount to heat pump customers that reflects a percentage of the difference between the marginal cost imposed on the grid in winter and the standard rate. For example, if the

[555] *Id.* at 3866.

[556] *Id.*

[557] *Id.* at 3870.

[558] *Id.* at 3870-71.

standard rate is $0.17/kWh and the winter marginal cost is $0.05/kWh, the EH/HP rate could reflect a discount of $0.06/kWh (i.e., half the $0.12/kWh overpayment) for a rate of $0.11/kWh. This option "would give EH/HP customers a reduced winter season energy rate, insulate nonparticipating customers from an unanticipated cost, and spread the benefit associated with any overcollection from heat pump customers to all ratepayers," "creat[ing] a win-win situation whereby rates encourage more heat pump adoption, reduce pollution and carbon emissions, reduce participant bills, and also reduce non-participant bills."[559] Mr. Reeves also presented examples of approved and proposed EH/HP rates from Massachusetts, Maine, Minnesota, and New York.[560]

Mr. Reeves recommended that the Commission direct Consumers to work with Staff and stakeholders to develop a proposal for an EH/HP to be presented to the Commission for approval within 12 months of the order in this case, either as part of the Company's next rate case or a stand-alone filing.[561] In developing such a rate, Mr. Reeves recommended that Consumers consider options for both seasonal and temporal differentiation, options for non-residential customers who electrify, pros and cons of a general electric heating rate versus a technology-specific rate aimed at promoting heat pump adoption, trade-offs of various eligibility and verification requirements (e.g., self-attestation, submetering), and education and delivery strategies (e.g., rate impact calculators, opt-out design).[562]

In rebuttal, Consumers witness Laura Connolly testified that the Company "does not oppose exploring an electric heat/heat pump rate design."[563] However, Consumers objects to Mr.

[559] *Id.* at 3871.

[560] *Id.* at 3872-75.

[561] *Id.* at 3848.

[562] *Id.* at 3848-49.

[563] Direct Testimony of Laura M. Connolly, 3 Tr 174.

Reeves's recommended 12-month timeframe, as the Company "would prefer to address this issue in the context of a general rate case" rather than a stand-alone filing, which could make the 12-month timeframe impracticable.[564] Ms. Connolly testified that the Company is willing to "explore developing an electric heat pump rate in its next general electric rate case," which "would allow all interested intervenors to comment and critique the Company's proposal," and that the Company "would endeavor to hold a stakeholder session in advance of that filing to solicit ideas of interested parties."[565]

MNSC recognizes the benefits of proposing an EH/HP rate as part of a general rate case proceeding, which the Company may or may not initiate within 12 months of the order in this case. However, it is important that the process of developing an EH/HP rate begins soon. As Mr. Reeves testified, the American Council for an Energy-Efficient Economy (ACEEE) "identified offering a heat pump specific electricity rate as the best approach to increase the adoption of heat pumps and guard against increasing energy bills associated with added electric heating loads."[566] Therefore, MNSC recommends that the Commission direct Consumers to begin developing an EH/HP rate and hold at least one stakeholder 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 considerations in Mr. Reeves's testimony in its next filed general electric rate case.

[564] *Id.*

[565] *Id.*

[566] *Id.* at 3875.

VII. OTHER ISSUES

A. Securitization of Test Year Tree Trimming, LVD Pole Spending

MNSC believe the following is the record on this issue: Direct Testimony of Company witness Patrick Daly, 3 Tr 1070-72, and his sponsored exhibit A-82; Direct Testimony of Company witness Marc Bleckman, 3 Tr 856-59; Direct Testimony of Company witness Jennifer Partlan, 3 Tr 1947-49; Direct Testimony of Company witness Sara Stewart, 3 Tr 2186-2234, and her sponsored exhibits A-170, A-173, and A-175; Direct Testimony of CUB witness Richard Bunch, 6 Tr 4023, 4048-55, 4060, 4072, and his sponsored exhibit CUB-26; Direct Testimony of NSC witness Douglas Jester, 6 Tr 3989-3997; Direct Testimony of AG witness Sebastian Coppola, 3 Tr 2581-82; Rebuttal Testimony of Staff witness Jessica Duell, 6 Tr 4408-10; Rebuttal Testimony of Company witness Marc Bleckman, 3 Tr 863-67; and Rebuttal Testimony of Company witness Patrick Daly, 3 Tr 1081-86.

In this case, the Company proposes dramatically increasing spending to accelerate work on its distribution system. Among other things, the Company aims to shorten cycles for LVD line clearing and eliminate significant backlog in LVD pole replacements.[567] For the test period, the Company proposes over $174,844,000 in total spending on its LVD line clearing program[568] and approximately $127,500,000 in total spending on its LVD pole replacement program.[569]

FIGURE 23
LINE CLEARING O&M ALTERNATE FUNDING MECHANISM PROPOSAL
TEST PERIOD

Description	HVD	LVD	Total
Total O&M Expense	$11,839,660	$174,844,314	$186,683,974
Baseline Expense	$11,839,660	$152,606,207	$164,445,867
Regulatory Asset	$0	$22,238,107	$22,238,107

[567] Jester Direct, 6 Tr 3989.

[568] Stewart Direct, Figure 23, 3 Tr 2231.

[569] Partlan Direct, Figure 35, 3 Tr 1956.

FIGURE 35

LVD LINES RELIABILITY INVESTMENT CATEGORY EXPENDITURES AND UNITS

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test Year # of Units
Targeted Circuit Improvement *strategies:*				
• Zonal Health Improvements	$61,320,000	497*	$34,917,000	175*
• Secondary	$19,680,000	66	$14,670,000	49
• Voltage Conversions	$8,427,000	44	$33,115,000	283
• Underground Cable Rejuvenation	$27,909,000	68	$65,989,000	158
ATR Loops	$17,539,000	39	$22,299,000	40
Pole Replacements	$29,711,000	3,076	$127,500,000	12,500
Circuit Exit Projects	$1,911,000	84	$3,616,000	197
Right-of-way	$6,188,000		$17,667,000	
Total	**$180,763,000**		**$312,886,000**	

Both of the Company's proposals involve a significant surge in spending above historic – baseline – levels, which is expected to diminish once programmatic changes are fully implemented.[570] In the case of line clearing and forestry work, the Company proposes regulatory asset treatment of above-baseline expenditures, which Company witnesses Stewart and Daly estimate will be over $22,238,000 in the test year.[571] The Company does not propose similar regulatory asset treatment for any part of the LVD pole replacement program.[572]

While MNSC raise no objections to the merits of the Company's proposed LVD line clearing and LVD pole replacement programs, MNSC remains concerned about the rate impacts

[570] Jester Direct, 6 Tr 3993 ("The balance of mildly increased repair or replacement frequency and lower cost per repair or replacement event may result in a modest increase or decrease of baseline spending levels, but historic spending levels adjusted for inflation are a reasonable estimate of the post-surge spending levels.").

[571] Stewart Direct, 3 Tr 2231; Daly Direct, 3 Tr 1071-72 ("The Company is seeking approval in this case to defer the 'ramp-up' related expenses as a regulatory asset once the 'ramp-up' begins through its completion.").

[572] Partlan Direct, 3 Tr 1956.

of this catch-up work on today's customers.[573] MNSC generally agrees with the Company's approach to defer above-baseline costs as regulatory assets,[574] though MNSC disagrees with the Company's methodology for calculating what constitutes "baseline."[575]

NSC witness Jester and CUB witness Bunch make two key recommendations aimed at mitigating the costs of the Company's above-baseline – "surge" – work. First, Jester recommends that the Commission "order Consumers to defer and propose to securitize its proposed spending for a surge in LVD pole replacements."[576] Second, Bunch and Jester recommend that the Commission defer and securitize all of the Company's surge line clearing costs, which are greater than the Company estimated in its application.[577]

1. The Company's plans for its LVD line clearing and LVD pole replacement programs include significant catch-up on backlogged maintenance work.

In Case No. U-21305, Liberty Consulting Group completed its audit of Consumers' distribution system. Among other things, the Liberty Audit "identified backlogs in tree trimming/vegetation maintenance and pole replacements and found that surge in both these areas would be especially cost-effective."[578] In this case, a considerable portion of Consumers' proposed

[573] Bunch Direct, 6 Tr 4048-49; see also Jester Direct, 6 Tr 3996 ("Consumers Energy's past failures to adequately maintain the distribution system, and particularly to spend adequately on current expenses like line clearing, should not enrich current shareholders by inordinately increasing rate base to catch up.").

[574] "Under the Company's proposal, any expenses incurred above the defined baseline would be deferred to the regulatory asset." Daly Rebuttal, 3 Tr 1082.

[575] Daly Rebuttal, 3 Tr 1082 (defining "baseline" as the "amount of funding that is included in rates for the test year").

[576] Jester Direct, 6 Tr 3997.

[577] Bunch Direct, 6 Tr 4047-48 (recommending that $72.7 million of forestry surge costs be securitized versus the $22.2 million recommended by the Company).

[578] Bunch Direct, 6 Tr 4049.

spending on the distribution system is to "shorten line clearing cycles…and to catch up on deferred maintenance investments," including pole replacements.[579]

The Company readily admits that it has a backlog in LVD vegetation maintenance[580] and needs to ramp up its line clearing program.[581] Currently, the Company aims to achieve a five-year clearing cycle across its LVD system by the end of the 2030-2031 test period, though as of now, the Company is still working toward a seven-year effective cycle.[582] To reach its target cycle, the Company "must devote significantly more spending towards the line clearing program compared to both historic spending levels and what will be required to maintain its five-year cycle one it is realized."[583] Jester testified – and the Company's data confirms – that after the line clearing surge is completed, line clearing work, and therefore, expense will be reduced.[584]

FIGURE 4
PLAN FOR LVD BACKLOG MILES ELIMINATION
FULL CIRCUIT CLEARING MILES

Vision Year	Plan Miles	On Cycle Miles	Backlog Miles	Backlog Miles Remaining
Year 1	9,019	5,279	3,740	26,684
Year 2	10,885	6,338	4,547	22,138
Year 3	12,814	6,365	6,449	15,689
Year 4	13,588	6,042	7,546	8,143
Year 5	14,837	6,694	8,143	0

[579] Jester Direct, 6 Tr 3989.

[580] Figure 4, below, depicts the Company's proposed workplan to eliminate the backlog in LVD vegetation maintenance.

[581] See Stewart Direct, 3 Tr 2199.

[582] See Stewart Direct, 3 Tr 2195 ("The Company has been working towards attaining a seven-year effective clearing cycle for its LVD system and has not yet attained this cycle.").

[583] Bunch Direct, 6 Tr 4052 (citing Stewart Direct, 3 Tr 2229).

[584] Jester Direct, 6 Tr 3989.

The Company also admits that it has a backlog of pole replacements: "The Company has had a backlog of poles identified in previous years' inspections for some time[] and has been working through this backlog through pole replacement projects each year."[585] According to witness Partlan, the Company is just beginning a groundline inspection program and expects that approximately 10% of the poles it inspects will be rejected and about 12,500 poles will need to be replaced in the test period.[586] By comparison, the Company replaced 149 poles in the 12-month test period ending February 28, 2026.[587]

The Company's implementation of a pole inspection and maintenance program is expected to create a temporary surge in pole replacement work and expense. According to witness Jester, periodic inspection and maintenance programs do not significantly affect the rate of failure of distribution system; rather, their benefit is to "identify incipient failures and to replace equipment before it fully fails and causes an outage."[588] While Jester explained that "more frequent inspections do not significantly affect the annual total number of repairs or replacements" long term, more frequent inspections do have a short-term effect. According to Jester, when the period between inspections is shortened, there will be a period of approximately the length of the new inspection cycle when additional replacement or repair are performed because the more frequent inspections observe more incipient failures that would have been replaced or repaired later upon full failure.[589] Jester elaborates:

[585] Partlan Direct, 3 Tr 1947.

[586] Jester Direct, 6 Tr 3996 (citing Partlan Direct, 3 Tr 1947).

[587] Bunch Direct, 6 Tr 4054 (citing Case No. U-21585, Direct Testimony of Donald A. Lynd, Figure 39, 4 Tr 579).

[588] Jester Direct, 6 Tr 3992.

[589] Jester Direct, 6 Tr 3992-93.

> The main benefit of more frequent inspections is that a larger share of incipient failures will be repaired before full failure and an outage. In other words, repairs or replacements during an incipient failure will happen sooner than if the repair or replacement is delayed until full failure. Thus, more frequent inspections to repair or replace equipment with incipient failures will shorten the expected service life of the equipment by the difference in time between inspection-based replacement of equipment with an incipient failure and when that equipment would have fully failed. Statistically, that difference will be half the average duration of an incipient failure. Therefore, the effect of more frequent inspections will be a modest increase in baseline frequency of repairs or replacements once a surge is complete. However, the utility costs of individual repairs or replacements will likely decrease when they are done to correct an incipient failure discovered through inspections compared to when they are done in response to outages.[590]

Based on Jester's analysis, "[t]he balance of mildly increased repair or replacement frequency and lower cost per repair or replacement event may result in a modest increase or decrease of baseline spending levels, but historic spending levels adjusted for inflation are a reasonable estimate of the post-surge spending levels."[591] Regardless of any other programmatic changes from the Company, it is clear that at least "some portion of Consumers Energy's pole defects is due to historic low inspection frequency and consequent low application of preventive maintenance practices."[592]

2. The Company's methodology for calculating baseline spending is speculative and novel.

Consumers and MNSC agree that expenses above baseline should be deferred as regulatory assets and securitized once the balance reaches an appropriate level.[593] According to witness Jester, deferring and securitizing surge costs serves "to reduce the rate impact of [] surge and to align the

[590] Jester Direct, 6 Tr 3993.

[591] Jester Direct, 6 Tr 3993.

[592] Jester Direct, 6 Tr 3994.

[593] See Jester Direct, 6 Tr 3991.

timing of cost recovery of the surge expenses with the timing of the resulting improvements in reliability."[594]

The parties disagree, however, about the methodology that should be used to calculate baseline versus surge expenses. To calculate surge expenses, the Company "uses a projection of expenses several years into the future to backcast the baseline costs of work performed in the test year."[595] According to Bunch and Jester, that approach is "speculative and novel" and backwards.[596] In any other expense category, the Company would adjust historical costs forward to estimate future costs.[597]

Rather than relying on forward-looking projection, CUB witness Bunch and NSC witness Jester recommend the Commission compare the Company's proposed spending with inflation-adjusted historical spending, the difference being the amount of surge spending.[598] AG witness Coppola endorses a similar approach.[599]

In rebuttal, Company witness Bleckman claims: "the baseline methodology proposed by Mr. Coppola and Mr. Bunch are without merit and should be rejected by the Commission."[600] Company witness Daly similarly claims that the "approach taken by AG witness Coppola and CUB witness Bunch is overly simplistic and fails to reflect the operational and strategic planning

[594] Jester Direct, 6 Tr 3991.

[595] Bunch Direct, 6 Tr 4053.

[596] Bunch Direct, 6 Tr 4053.

[597] Bunch Direct, 6 Tr 4053.

[598] Bunch Direct, 6 Tr 4053

[599] Coppola Direct, 3 Tr 2582 (recommending the Company defer all line clearing expenses above the 2024 line clearing expense amount of $110,225,000).

[600] Bleckman Rebuttal, 3 Tr 867.

embedded in the Company's [proposal]."[601] Daly claims their approach "disregards changes that are appropriately considered in a projected test year" – that "the use of a projected test year is intended to account for such forward-looking changes."[602] Those claims are not supported by Commission precedent.

The Commission has previously stated "its preference for a historically based test year adjusted for *known* and *measurable* changes," finding that a "properly adjusted historical test year provides a firm, prudent, and practical basis for setting appropriate rates for the future period."[603] In Case No. U-13898, for example, the Commission found that a test year relying on actual and verifiable information from a known starting point was far more objective and prudent than a test year based on speculative increases in presently authorized expenses.[604]

Consistent with Commission precedent, witness Bunch calculated the Company's baseline, test year spending using historically based data adjusted for "known and measurable changes," such as inflation.[605] By comparison, the Company uses a projection of its annual expense to maintain the "five-year cycle after it is achieved in the 2030-2031 test period, adjusted (or deflated) to the projected test period dollars."[606] Like the projection that the Commission rejected in Case No. U-13898, the Company's projected future expenditures are subject to change and are not certain to occur as forecasted.[607]

---

[601] Daly Rebuttal, 3 Tr 1082.

[602] Daly Rebuttal, 3 Tr 1083.

[603] E.g., Case No U-13898, Order, April 28, 2005, pp 10-11 (discussing an application to increase rates based upon a projected test year).

[604] See *Id*. at 10 ("[T]he Commission simply is not persuaded of the accuracy of a substantial number of the projections and the proposed futured events contained within [the utility's] testimony and its supporting documentation.").

[605] See Bunch Direct, 6 Tr 4048.

[606] Bunch Direct, 6 Tr 4052-53 (citing Stewart Direct, 3 Tr 2218).

[607] Case No. U-13898, Order, April 28, 2005, p 8.

Also in rebuttal testimony, Company witness Daly defends the Company's baseline methodology and opposes the methodology supported by Coppola and Bunch.[608] He refers to witness Bleckman's rebuttal and argues that, by deferring and securitizing some of the ramp up costs, "the Company is mitigating immediate customer rate impacts."[609] While that is accurate, it does not mean there is not room for more – by securitizing more of the forestry costs and including LVD pole replacement costs in the regulatory asset, the Company would be further mitigating customer rate impacts.

Witness Daly also makes the argument that the Company's increasing authorized and actual forestry spending over the last five rate cases reflects "the Company's commitment to achieving a shorter forestry cycle," referencing Figure 20 of witness Stewart's direct testimony:[610]

FIGURE 20
LINE CLEARING PROGRAM SPEND AUTHORIZED TO ACTUAL

MPSC Case No.	Timeframe	Authorized Spend ($M)	Actual Spend ($M)	Difference in Authorized Spend and Actual Spend ($M)
U-20697	January 2021 - December 2021	$84.000	$86.567	$2.567
U-20963	January 2022 - December 2022	$93.959	$102.003	$8.044
U-21224	January 2023 - December 2023	$100.030	$109.093	$9.063
U-21389	March 2024 - February 2025	$118.890	$119.189	$0.299
U-21585	March 2025 - February 2026	$125.408[9]	$125.408[10]	$0.000
Total	January 2021 - February 2026	$522.287	$542.260	$19.973

According to Daly, Coppola's and Bunch's baseline amounts are less than the $125 million authorized in U-21585. Given the upward trend and the current authorized spending, Daly claims

[608] Daly Rebuttal, 3 Tr 1083-85.

[609] Daly Rebuttal, 3 Tr 1084.

[610] Daly Rebuttal, 3 Tr 1085 (referencing Stewart Direct, Figure 20, 3 Tr 2226).

it would be unreasonable to set the baseline below the current spending level. This argument is flawed in two ways. First, while the Company's spending levels increased each year from 2021 through 2026, the number of LVD miles cleared has remained static or decreased in the last few years:[611]

	2021	**2022**	**2023**	**2024**	**2025**
O&M Full Circuit Clearing Miles	4,647	5,653	5,758	5,400	6,108
O&M Subprogram Clearing Miles	238	247	244	244	244
Capital Clearing Miles	252	221	168	258	325

To the extent annual authorized spending is increasing, that reflects increasing costs per mile as much as the number of LVD miles cleared annually:[612]

	2021	**2022**	**2023**	**2024**	**2025**
O&M Expense ($M)	$75.83	$91.02	$97.79	$99.49	$113.20
Capital Contractor Costs ($M)	$6.07	$6.71	$5.59	$9.69	$14.01

As to Daly's concern that Bunch's and Coppola's baseline levels are below 2025 approved levels, this is of no consequence. The Company's current and historic line clearing plans includes catching up the backlog of circuits, so the current approved spending levels reflect the cost of catching up.[613] In fact, according to the Company's forestry management witness in U-21585 (witness

[611] Stewart Direct, Figure 12, 3 Tr 2218.

[612] *Id.*

[613] Stewart Direct, 3 Tr 2195-96 (addressing work to clear LVD backlog).

Bolden), most of the Company's planned line clearing miles for 2024 and 2025 are backlog miles:[614]

FIGURE 8
FORESTRY PLAN FOR BACKLOG MILES REDUCTION

Forestry Backlog Reduction Plan 2024-2030				
Year	**Plan Miles**	**On Cycle Miles**	**Backlog Miles**	**Backlog Miles Remaining**
2024	6,760	1,690	5,070	20,249
2025	7,232	2,170	5,062	15,187
2026	7,449	2,980	4,469	10,718
2027	7,672	3,836	3,836	6,882
2028	7,932	4,759	3,173	3,709
2029	8,316	5,821	2,495	1,214
2030	8,699	7,485	1,214	0

It is not unreasonable that Bunch's baseline is below the Company's current authorized spending level because the current authorized level also includes surge spending – i.e., spending to catch up on off-cycle (backlog) circuits. Finally, as discussed, Bunch applied known and reasonable increases (productivity-adjusted inflation) to the Company's historical year (2024) to derive the baseline, which is a reasonable and reliable method to ascertain baseline spending.

In rebuttal, Staff witness Duell supports the Company's baseline methodology over the methodologies proposed by witness Bunch and Coppola because it should "ultimately result in less expense going into the regulatory asset over the next five years," meaning lower interest expense to ratepayers in the long run.[615] Conversely, the Company's methodology would raise operating expenses, which are not amortized, and cause more immediate impacts to customers' rates. Bunch based his recommendation, in part, on the concern that today's customers should not

[614] Case No. U-21585, Bolden Direct, 3 Tr 219.

[615] Duell Rebuttal, 6 Tr-4409-10.

assume the full financial burden for the "Company's past managerial decisions that resulted in backlogged maintenance and poor reliability performance."[616] As Bunch noted, a growing number of customers are already struggling because the Company's rates are already high and have risen faster than inflation.[617] If the Company's proposed costs and allocations are adopted for these surge programs, residential rates will increase "by over 13%" in the test year, causing likely rate shock.[618] Witness Bunch's recommendations mitigate those rate impacts by deferring and securitizing a realistic estimate of surge spending.

3. The Company's distinction between LVD line clearing surge (O&M) and LVD pole replacement surge (capital) is artificial.

As discussed above, witnesses Jester and Bunch propose regulatory asset treatment and eventual securitization of the Company's surge in LVD pole replacements.[619] In rebuttal, Company witness Daly "objects to the use of securitizations for these investments in its distribution system."[620] According to Daly, utility securitizations have historically "been reserved for the recovery of stranded costs associated with assets that no longer provide a benefit to customers and/or material non-recurring expenses."[621] Daly's argument is that surge operating expenses can be securitized, but surge capital expenses cannot.[622] Company witness Kelly similarly rebutted witness Bunch's recommendation to securitize LVD pole surge spending.[623] He referenced witness

[616] Bunch Direct, 6 Tr 4050.

[617] Bunch Direct, 6 Tr 4049.

[618] See Bunch Direct, 6 Tr 4049.

[619] Bunch Direct, 6 Tr 4029.

[620] Daly Rebuttal, 3 Tr 1086.

[621] Daly Rebuttal, 3 Tr 1086.

[622] See Daly Rebuttal, 3 Tr 1086.

[623] Kelly Rebuttal, 3 Tr 1613.

Daly's rebuttal and further noted that "it is not reasonable to remove the capital costs for pole replacement from rate base" on the basis pole replacement is capital spending that is depreciated over multiple years. The Company's distinction between operating expenses and capital expenses is artificial.

There is no practical reason to oppose securitization of surge costs that are capital (as opposed to operating expenses). The intent of securitization of surge spending is to mitigate rate impacts to customers beyond the benefits of depreciation. Securitization offers the opportunity to reduce the total amount recovered from ratepayers relative to traditional cost recovery; whether the costs incurred are expense or capital.

While Daly may be correct that the Commission has previously used the securitization mechanism to mitigate rate impacts from stranded assets and surge operational expenses, he cites no precedent establishing that it can only be used in those cases. Notably, Public Act 142 of 2000 – which amended Public Act 3 of 1939, MCL 460.1 *et seq*., and authorized the securitization mechanism – does not include such a limitation.

According to Daly, the reason the Company proposed securitizing forestry ramp up expenditures was to "mitigate the rate impacts from the increase in operating expenses."[624] However, as Jester and Bunch testified, the reasons for securitizing LVD pole replacements are nearly identical to the reasons for securitizing line clearing expenditures. For example, Jester noted that deferring and securitizing surge in capital spending would mitigate rate impacts of the surge by helping "align the timing of cost recovery with the timing of reliability benefits."[625] Jester and Bunch also explained that the need for a LVD pole replacement surge exists for similar reasons as

[624] Daly Rebuttal, 3 Tr 1086.

[625] Jester Direct, 6 Tr 3996.

the reasons for a LVD line clearing surge – i.e., because of the Company's deficient preventive maintenance practices.[626] Deferring and securitizing the surge in capital costs of an LVD pole replacement surge will help ensure that current shareholders are not inordinately enriched by programmatic catch up at the expense of ratepayers.[627] As Jester notes, the "cost of financing the surge expenditures through securitization bonds will be considerably less than Consumers Energy's authorized weighted cost of capital, helping to mitigate, though not eliminating, the rate impacts of the surge."[628]

4. The Company's concerns about its credit metrics are unsubstantiated.

In direct testimony, Company witness Bleckman argued that the regulatory asset used for forestry should not be financed using the short-term debt rate, and instead, the Commission should use the pre-tax weighted average cost of capital ("pre-tax WACC").[629] Bleckman states: "[w]ere the regulatory asset 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."[630] 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

[626] Jester Direct, 6 Tr 3994-95 (noting that the Company's LVD pole replacement proposal is due to historic low inspection frequency and consequent low application of preventive maintenance practices).

[627] See Jester Direct, 6 Tr 3996 ("Securitization of capital expenditures places surge investments outside Consumers Energy's rate base.").

[628] Jester Direct, 6 Tr 3996.

[629] See Bleckman Direct, 3 Tr 857-58.

[630] Bleckman Direct, 3 Tr 858 (using a pre-tax WACC rate equal to 7.4% and a short-term debt rate equal to 4.3%).

approximately 5% if the asset balance is assumed to be financed with short-term debt.[631] The Company's calculations are reproduced below:

FFO/Debt Ratio of Forestry Deferral as Standalone

Example: $100 million Regulatory Asset Balance

	As Filed (Pre-tax WACC)	Proforma (Short-Term Debt)
FFO, mils	$ 7.4	$ 4.3
Debt, mils	41.6	84.8
FFO/Debt	**17.7%**	**5.0%**

Calculations (Percentages based on Order in U-21585)

As Filed FFO: $100 mil x 7.38% pre-tax WACC

As Filed Debt: $100 mil x 41.6% LT debt pct of total cap.

Proforma FFO: $100 mil x 4.28% short-term debt rate

Proforma Debt: $100 mil x 84.8% (total cap. less DFIT)

Bleckman concluded that "due to the harmful credit impacts," the short-term debt rate is "not an acceptable financing assumption for the deferred 'ramp-up' regulatory asset."

The Company does not support its case, however, with evidence of expected impacts on the Company's overall credit.[632] For example, Bleckman states: "[i]t is worth noting, for comparison purposes, that 18% is Moody's downgrade threshold for the company so this would not add any padding to the Company's position."[633] The Company did not perform analyses calculating the company-wide FFO-to-Debt ratio if the Commission applies the short-term debt rate to the proposed regulatory assets.[634] While the Company provides some historical data of its

[631] Bleckman Direct, 3 Tr 859.

[632] Bleckman Direct, 3 Tr 859; Bleckman Rebuttal, 3 Tr 864 (financing the regulatory asset with debt "would add additional strain to the Company's credit metrics").

[633] Bleckman Direct, 3 Tr 859.

[634] Ex MEC 45, U21870-MNSC-CE-868.

FFO-to-Debt ratios relative to credit agencies' downgrade thresholds, it does not provide data showing that using the short-term debt rate would likely cause a downgrade.[635]

In rebuttal, Bleckman also claimed that Bunch and Coppola's baseline methodologies should be rejected because they would result in "lower funding and higher deferred costs," which "places undue additional pressure on the Company's credit metrics as a result of lower cash and higher financing that would be necessary."[636] Again, the Company has not shown that Bunch and Coppola's proposals would result in a credit downgrade. In other rate cases, the Commission has approved comparably large regulatory assets and applied the short-term debt rate.[637]

5. MNSC recommends deferring and securitizing the full extent of the Company's programmatic surge, which should be determined by adjusting historical test year spending.

The Commission should adopt the recommendations from witnesses Jester and Bunch and direct Consumers to defer and propose to securitize surge spending on the Company's LVD line clearing and LVD pole replacement programs. Adjusting the Company's historical test year spending for PAI (discussed above under Inflation Factors), Bunch determined that baseline spending for the LVD line clearing program and LVD pole replacement programs is about $114 million and $25 million, respectively.[638] Costs that exceed those baselines represent increased activity over adjusted baseline, or surge.[639] If the Commission grants the Company's proposed spending in full, MNSC recommends "regulatory asset treatment and potential securitization" of

[635] See Bleckman Direct, 3 Tr 821.

[636] Bleckman Rebuttal, 3 Tr 867.

[637] E.g., Case No. U-20162, Order, May 2, 2019, p 134.

[638] Bunch Direct, 6 Tr 4053, 4055.

[639] Bunch Direct, 6 Tr 4053.

approximately $72.7 million in LVD line clearing costs and $102.5 million in LVD pole replacement costs.[640]

VIII. CONCLUSION

For the reasons discussed above, MNSC respectfully requests that the Commission:

A. Reduce the Company's proposed test year investment in LVD undergrounding by $15.4 million;

B. Disallow inclusion in rate base of $5.28 million in capital expenditures for two projects at the Jackson gas plant;

C. Direct the Company to revise its internal fleet electrification target so that all light-duty vehicle replacements are electric by 2030;

D. Approve Consumers' transportation electrification plan (TEP) with modifications as detailed in witness Jester's testimony;

E. Reject Consumers' proposed 50.75% equity ratio and maintain the Company's current authorized balanced capital structure;

F. Reject Consumers' requested ROE of 10.2% and authorize an ROE of 9.22%;

G. Reject the Company's Service Restoration Resiliency Fund proposal;

H. Reject the Company's Extraordinary Storm Accounting proposal or, in the alternative, explore it in a separate docket;

[640] Bunch Direct, 6 Tr 4053, 4055.

I. Disallow $59.5 million from test year O&M expenses as a result of adjusting inflation factors by productivity offsets;

J. Deny approval of Consumers' change in distribution cost allocation method to assign distribution plant costs only to downstream voltage levels;

K. Allocate distribution batter costs to all distribution customers;

L. Allocated the cost the MAOAM project to commercial and industrial customers;

M. Allocate AMI costs in proportion to its relative benefits, which are 36% energy-related, 17% demand-related, and 47% customer-related;

N. Deny approval to add a facilities allowance to Rate LED, increase the system contribution charge from 1% to 25% of embedded system production costs, and shorten the maximum contract length to 7 years;

O. Order regulatory asset treatment and subsequent securitization of the Company's above-baseline spending to ramp up forestry work and LVD pole replacements;

P. Reduce the amount of Consumers' proposed annual authorized amounts for LVD Lines Reliability in its Distribution IRM by at least $108.8 million per year; and

Q. Direct Consumers to develop an electric heating (EH) or heat pump (HP) rate for presentation in its next filed rate case in accordance with witness Reeves's testimony.

Respectfully submitted,

TROPOSPHERE LEGAL, PLC
Counsel for MNSC

Date: December 5, 2025

By: 

Christopher M. Bzdok (P53094)
Tracy Jane Andrews (P67467)
Holly L. Hillyer (P85318)
420 E. Front St.
Traverse City, MI 49686
Phone: 231-709-4000

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

PROOF OF SERVICE

On the date below, an electronic copy of **Initial Brief by Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan** was served on the following:

Name/Party	E-mail Address
ALJ Hon. Jonathan F. Thoits	thoitsj@michigan.gov
Consumers Energy Company Anne M. Uitvlugt Bret A. Totoraitis Evan B. Keimach Gary A. Gensch Jr. Spencer A. Sattler Kelly Hall Mark R. Ruszkiewicz	mpsc.filings@cmsenergy.com anne.uitvlugt@cmsenergy.com bret.totoraitis@cmsenergy.com evan.keimach@cmsenergy.com gary.genschjr@cmsenergy.com spencer.sattler@cmsenergy.com kelly.hall@cmsenergy.com mark.ruszkiewicz@cmsenergy.com
Michigan Attorney General Celeste R. Gill Lucas Wollenzien	ag-enra-spec-lit@michigan.gov gillc1@michigan.gov wollenzienl@michigan.gov
Michigan Public Service Commission Staff Daniel E. Sonneveldt Nicholas Taylor Michael J. Orris Lori Mayabb Amit T. Singh Alena M. Clark Adam M. Cozort	sonneveldtd@michigan.gov taylorn10@michigan.gov orrism@michigan.gov mayabbl@michigan.gov singha9@michigan.gov clarka55@michigan.gov cozorta1@michigan.gov
Great Lakes Renewable Energy Association Don L. Keskey Carol Dane	dkeskey@publiclawresourcecenter.com cdane@publiclawresourcecenter.com
Walmart, Inc. Melissa M. Horne	mhorne@hcc-law.com

Association of Businesses Advocating Tariff Equity (ABATE)	
Stephen A. Campbell	scampbell@clarkhill.com
Benjamin J. Holwerda	bholwerda@clarkhill.com
Michael J. Pattwell	mpattwell@clarkhill.com
James Dauphinais	jdauphinais@consultbai.com
Lauren Degnan	ldegnan@clarkhill.com
Christina Hildebrandt	childebrandt@consultbai.com
Jessica York	jyork@consultbai.com
Hemlock Semiconductor Operations, LLC	
Jennifer U. Heston	jheston@potomaclaw.com
The Kroger Company	
Michael L. Kurtz	mkurtz@bkllawfirm.com
Kurt J. Boehm	kboehm@bkllawfirm.com
Jody Kyler Cohn	jkylercohn@bkllawfirm.com
Justin Bieber	jbieber@energystrat.com
Michigan Cable Telecommunications Association	
Sean P. Gallagher	sgallagher@fraserlawfirm.com
Jon Austin	jaustin@fraserlawfirm.com
Counsel for Energy Michigan, Foundry Association of Michigan, Michigan Energy Innovation Business Council ("Michigan EIBC"), Institute for Energy Innovation ("IEI"), Advanced Energy United ("United"), Energy Michigan Inc., and The Foundry Association of Michigan.	
Timothy J. Lundgren	tjlundgren@varnumlaw.com
Justin K. Ooms	jkooms@varnumlaw.com
Laura A. Chappelle	lachappelle@varnumlaw.com
Lydia Lubbers	lmlubbers@varnumlaw.com
Urban Core Collective	aelc_mpsc@lawclinic.uchicago.edu
Amanda Urban	aurbanlaw@gmail.com
Mark Templeton	templeton@uchicago.edu
Jacob Schuhardt	jschuhardt@uchicago.edu
Emma Young	eyoung28@uchicago.edu
Alexandria Miskho	amiskho@uchicago.edu
The Ecology Center, Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar (CEO)	MPSCDocket@elpc.org
Daniel Abrams	dabrams@elpc.org
Katie Duckworth	kduckworth@elpc.org
Alondra Estrada	aestrada@elpc.org
Katie Toolan	ktoolan@elpc.org
Michigan Electric Transmission Company	mpscfilings@dykema.com
Olivia R.C.A. Flower	oflower@dykema.com
Richard J. Aaron	raaron@dykema.com
Courtney F. Kissel	ckissel@dykema.com
Anthony J. Hunt	ahunt@dykema.com
Hannah Buzolits	HBuzolits@dykema.com

[signature page below]

The statements above are true to the best of my knowledge, information and belief.

Troposphere Legal, PLC
Counsel for MNSC

Date: December 5, 2025

By: Digitally signed by Natasha Fowles Date: 2025.12.05 16:36:00 -05'00'

Natasha Fowles, Legal Assistant
420 E. Front St.
Traverse City, MI 49686
Phone: 231-709-4900
Email: natasha@tropospherelegal.com