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September 27, 2024

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Highway
P.O. Box 30221
Lansing, MI 48909

Re: **MPSC Case No. U-21585**

Dear Ms. Felice:

Attached for electronic filing in the above-referenced matter, please find the Direct Testimony of Dr. Laura S. Sherman; Direct Testimony of John D. Albers; Direct Exhibit List; Exhibits of Dr. Laura S. Sherman; and Exhibits of John D. Albers on behalf of the Michigan Energy Innovation Business Council, The Institute for Energy Innovation, and Advanced Energy United, together with the Proof of Service.

Thank you for your assistance in this matter.

Very truly yours,

Justin K. Ooms Digitally signed by Justin K. Ooms
Date: 2024.09.27 11:25:23 -04'00'

Justin K. Ooms

JKO/srd
All parties of record.
Enclosures.

**STATE OF MICHIGAN**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

*****

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for<br>the generation and distribution of<br>electricity and for other relief. | )<br>)<br>)<br>)<br>)<br>)<br>) | **Case No. U-21585** |

# DIRECT TESTIMONY OF DR. LAURA S. SHERMAN

**ON BEHALF OF**

**THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL,**

**INSTITUTE FOR ENERGY INNOVATION,**

**AND**

**ADVANCED ENERGY UNITED**

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## I. INTRODUCTION AND QUALIFICATIONS

**Q. State your name, business name and address.**

A. My name is Dr. Laura S. Sherman, and I am the President of the Michigan Energy Innovation Business Council ("Michigan EIBC") and the Institute for Energy Innovation ("IEI"), located at 115 West Allegan, Suite 710, Lansing, Michigan 48933.

**Q. On whose behalf are you appearing in this case?**

A. I am appearing here as an expert witness on behalf of Michigan EIBC, IEI, and Advanced Energy United ("United"), collectively referred to as "MEIU."

**Q. Summarize your educational background.**

A. I have a Ph.D. from the University of Michigan Earth and Environmental Sciences Department, conferred in May 2012. I also have a Bachelor of Science degree from Stanford University in Geological and Environmental Sciences, conferred in June 2005.

**Q. Summarize your experience in the field of electric utility regulation.**

A. Since April 2019, I have served as the President of Michigan EIBC and IEI. Prior to that, starting in February 2017, I was a Senior Consultant at 5 Lakes Energy focusing on energy policy and utility regulation. I also served as the Vice President for Policy Development for the Michigan EIBC and IEI. In these capacities, I have written testimony in many non-adjudicated dockets before the Michigan Public Service ("Commission" or "MPSC"). From 2014–2016, I served as a Policy Advisor on energy, environment, and agriculture issues to Senator Michael Bennet (D-CO) in the U.S. Senate. In that capacity, I provided

policy expertise, conducted research, developed legislation, and analyzed regulations. Prior to that, my doctoral (2007–2012) and postdoctoral (2012–2014) research was focused on the tracing of pollutants emitted during energy generation. My work experience is set forth in detail in my résumé, attached as Exhibit MEIU-1 (LSS-1).

**Q. Summarize your professional development coursework in the field of electric utility regulation.**

A. In August 2017, I completed the Electric Utility Consultants Inc. ("EUCI") course titled "Optimizing the Interconnection Process for Renewables & Storage: A National Forum for Addressing Process and Technical Issues." In December 2017, I completed the EUCI course titled "The Electric Vehicle-Utility Industry Nexus." In January 2018, I completed the EUCI course titled "Evolution of Electricity Markets: Disruptive Innovation & Economic Impacts: Highly Interactive Course Designed to Provide A Practical Overview of Evolving U.S. Power Markets."

**Q. Have you testified before this Commission or as an expert in any other proceeding?**

A. Yes. I previously testified as an expert witness in the following cases:

- U-20134 (Consumers Energy Company ["Consumers Energy," "Consumers," or the "Company"] general electric rate case);
- U-20165 (Consumers Energy Integrated Resource Plan case);
- U-20162 (DTE Electric Company ["DTE Electric"] general electric rate case);
- U-20471 (DTE Electric Integrated Resource Plan ["IRP"] case);
- U-18232 (DTE Electric Renewable Energy Plan case);
- U-20649 (Consumers Energy Voluntary Green Pricing Program case);

- Consolidated U-20713 (DTE Electric Voluntary Green Pricing Program case)/U-20851 (DTE Electric Renewable Energy Plan case);
- U-20693 (Consumers Energy general electric rate case);
- U-21090 (Consumers Energy IRP case);
- U-21131 (Consumers Energy Legally Enforceable Obligation case);
- U-21134 (Consumers Energy Voluntary Green Pricing Program case);
- U-20836 (DTE Electric general electric rate case);
- U-21224 (Consumers Energy general electric rate case);
- U-21172 (DTE Electric Voluntary Green Pricing Program case);
- U-21193 (DTE Electric IRP case);
- U-21297 (DTE Electric general electric rate case);
- U-21374 (Consumers Energy Voluntary Green Pricing Program case);
- U-21389 (Consumers Energy general electric rate case);
- U-21534 (DTE Electric general electric rate case); and
- U-21482 (DTE Electric interconnection procedures case).

**Q. Have you provided analysis in support of testimony or comments in any other utility regulatory proceeding?**

A. Yes, I have provided comments with input from Michigan EIBC member companies in a number of different proceedings including:

- U-18351 and U-18352 (development of voluntary green pricing programs);
- U-20095 (Public Utility Regulatory Policies Act of 1978 ["PURPA"] regulations and capacity determinations);
- U-18383 (development of a distributed generation ["DG"] tariff);
- U-18361 (code of conduct rules);
- U-20147 (distribution system planning and utility distribution system plans);

- U-20905 (implementation of Federal Energy Regulatory Commission ["FERC"] Order 872);
- U-20890 (Interconnection and Distributed Generation Standards);
- U-20898 (utility business models);
- U-21099 (demand response aggregation);
- U-21219 and U-18461 (IRP Filing Requirements and Planning Parameters);
- U-20959 (customer data access);
- U-21251 (grid system data access);
- U-21400 (performance based regulation/reliability metrics);
- U-21547 (implementation of PA 233 regarding wind/solar/storage siting);
- U-21568 (implementation of PA 235 regarding the renewable portfolio standard);
- U-21569 (implementation of PA 235 regarding the DG Program);
- U-21567 (implementation of PA 239 regarding energy efficiency and electrification); and
- U-21571 (implementation of PA 235 regarding the energy storage mandate).

In addition to this work, I have been involved on behalf of Michigan EIBC in multiple workgroup proceedings at the Commission, including those focused on electric vehicle ("EV") deployment, DG tariffs, IRP requirements, energy waste reduction, and distribution system planning. I was involved on behalf of Michigan EIBC/IEI in the MI Power Grid workshop proceedings at the Commission, including those focused on new technologies and business models, customer data access, updating the state's interconnection rules, demand response, distribution system planning, pilot programs, competitive procurement, advanced planning, and updating the IRP parameters and filing requirements.

**Q. Please summarize your experiences working with advanced energy companies on issues related to electric utility regulation.**

A. I have served as the President of Michigan EIBC and IEI since April 2019. Prior to that, from November 2017 through April 2019, I served as Vice President of Policy Development for Michigan EIBC and IEI. In these roles, I have led the trade organization's work on regulatory and legislative issues. As described above, I have participated in many workgroups at the Commission and written comments in a number of non-adjudicated cases. I also communicate formally and informally with Michigan EIBC member companies about each regulatory proceeding to understand how the advanced energy industry is affected by each proposed rule or case.

**Q. What is the purpose of your testimony?**

A. The purpose of my direct testimony is to express support for certain aspects of the Company's EV proposals as well as describe proposed modifications thereto, address issues related to the Company's proposal to develop a tariff to allow land lease payments to be made as utility-bill credits, and address concerns related to Advanced Metering Infrastructure ("AMI").

**Q. Are you sponsoring any exhibits?**

A. Yes, I am sponsoring the following exhibits:

- Exhibit MEIU-1 (LSS-1): Résumé of Dr. Laura S. Sherman
- Exhibit MEIU-2 (LSS-2): Discovery response MEIU-CE-0092
- Exhibit MEIU-3 (LSS-3): Discovery response MEIU-CE-0071

- Exhibit MEIU-4 (LSS-4): Discovery response MEIU-CE-0073
- Exhibit MEIU-5 (LSS-5): Discovery response MEIU-CE-0072
- Exhibit MEIU-6 (LSS-6): Discovery response MEIU-CE-0261
- Exhibit MEIU-7 (LSS-7): Discovery response MEIU-CE-0076
- Exhibit MEIU-8 (LSS-8): Discovery response MEIU-CE-0075
- Exhibit MEIU-9 (LSS-9): Discovery response MEIU-CE-0258
- Exhibit MEIU-10 (LSS-10): Discovery response MEIU2-CE-0257
- Exhibit MEIU-11 (LSS-11): Discovery response MEIU-CE-0080
- Exhibit MEIU-12 (LSS-12): Discovery response MEIU-CE-0263
- Exhibit MEIU-13 (LSS-13): Discovery response MEIU-CE-0506

## II. TRANSPORTATION ELECTRIFICATION

**Q. Please summarize your view of the Company's transportation electrification proposals in this case.**

A. Consumers Energy's proposals regarding transportation electrification are presented in the testimony of Jeffrey A. Myrom.[1] Witness Myrom describes several proposals to modify existing transportation electrification proposals without proposing any additional spending on these programs. The Company has three primary EV programs: (1) PowerMIDrive Residential, which provides rebates for Level 2 EV chargers at single- and multi-family homes; (2) PowerMIDrive Public, which provides rebates for destination and community

[1] Direct Testimony of Jeffrey A. Myrom on behalf of Consumers Energy Company ("Myrom Direct"), Case No. U-21585.

EV chargers; and (3) PowerMIFleet, which provides rebates for fleet and workplace EV chargers. As described in the Company's Transportation Electrification Plan filed in Case No. U-21538, the Company is focused on maximizing off-peak charging in all of these programs to ensure that the EV programs benefit all customers by reducing distribution system needs and impacts.[2]

## A. BENEFIT-COST ANALYSIS

**Q. From your review of utility Transportation Electrification Plans ("TEPs"), what elements are essential to a robust benefit-cost analysis ("BCA")?**

A. Objective, robust BCAs with clearly stated assumptions that inform benefit-cost calculations allow utilities, public utility commissions, and other interested stakeholders to assess proposed utility investments, including those in TEPs, with greater transparency and clarity.[3, 4, 5] I reviewed TEPs from seven utilities: Commonwealth Edison ("ComEd,"

[2] Consumers Energy, "Transportation Electrification Plan 2024," Case No. U-21538, filed June 25, 2024, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000EFQgtAAH.

[3] Shenot, J., *Regulatory Assistance Project*, "Using Benefit-Cost Analysis to Improve Distribution system Investment Decisions," November 2022, available at https://www.raponline.org/wp-content/uploads/2023/09/rap-shenot-prause-shipley-using-benefit-cost-analysis-issue-brief-2022-november.pdf.

[4] *See for example* State of New York Public Service Commission, Case 14-M-0101, "Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision: Order Establishing the Benefit Cost Analysis Framework," January 2016, available at https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BF8C835E1-EDB5-47FF-BD78-73EB5B3B177A%7D.

[5] Direct Testimony of Courtney Lane, Case Number 9695, "In the Matter of the Application of the Potomac Edison Company for Adjustments to its Retail Rates for the Distribution of Electric Energy," June 2023, available at https://www.synapse-energy.com/sites/default/files/23-048%20Lane%20Direct%20Testimony%20-%20CN%209695%20-%20Public%20Version%20-%20FINAL.pdf.

2022),[6] Consolidated Edison ("ConEd," 2020),[7] National Grid Massachusetts ("National Grid," 2021),[8] Southern California Edison ("SCE," 2020),[9] Xcel Colorado (2021),[10] Xcel Minnesota (2022),[11] and Ameren Illinois ("Ameren," 2022).[12] Of the TEPs that I reviewed, ComEd,[13] Xcel Colorado,[14] Xcel Minnesota,[15] and Ameren[16] all included a BCA. In

[6] Illinois Commonwealth Edison, "ComEd Beneficial Electrification Plan," 2022, available at https://icc.illinois.gov/docket/P2022-0432/documents/325766/files/567114.pdf.

[7] Consolidated Edison Company of New York, Inc., Case 18-E-0138, "Electric Vehicle Infrastructure Make-Ready Program Implementation Plan," September 2020, available at https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b181AB1C0-0F11-44F6-B652-5705D91EC1B3%7d.

[8] Massachusetts Electric Company and Nantucket Electric Company each D/B/A National Grid, "Direct Pre-Filed Testimony of the Electric Vehicle Program Panel," Exhibit NG-EVPP-1, July 2021, available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/13758106.

[9] Southern California Edison Company, "Application of Southern California Edison Company (U338E) for Approval of its Charge Ready 2 Infrastructure and Market Education Programs," Application 18-06-015, September 2020, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M346/K230/346230115.PDF.

[10] Colorado Xcel Energy, "Transportation Electrification Plan: 2021 – 2023," available at https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/20A-0204E-_2021-2023_TEP_Updated.pdf.

[11] Minnesota Xcel Energy, "Petition of Northern States Power Company for Approval of a Public Charging Network, an Electric School Bus Pilot, and Program Modifications," 2022, available at https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={90B25F82-0000-C32B-B70E-1C25A3E2A491}&documentTitle=20228-188061-07.

[12] Ameren Illinois Company, "Beneficial Electrification Plan," 2022, available at https://www.icc.illinois.gov/docket/P2022-0431/documents/325722/files/567031.pdf.

[13] Illinois Commonwealth Edison, "ComEd Beneficial Electrification Plan," 2022, available at https://icc.illinois.gov/docket/P2022-0432/documents/325766/files/567114.pdf.

[14] Xcel Colorado Energy, "Benefit-Cost Analysis of Transportation Electrification in the Xcel Energy Colorado Service Territory," May 2020, available at https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=926529&p_session_id=.

[15] Minnesota Xcel Energy, "Petition of Northern States Power Company for Approval of a Public Charging Network, an Electric School Bus Pilot, and Program Modifications," 2022, available at https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={90B25F82-0000-C32B-B70E-1C25A3E2A491}&documentTitle=20228-188061-07.

[16] Ameren Illinois Company, "Beneficial Electrification Plan," 2022, available at https://www.icc.illinois.gov/docket/P2022-0431/documents/325722/files/567031.pdf.

addition, while it did not conduct its own BCA, National Grid[17] utilized evidence from a BCA conducted by the New York Public Service Commission Staff[18] as the basis for evaluation of its proposed public and workplace make-ready programs.[19]

Several states including Colorado,[20] Illinois,[21] and Minnesota[22, 23] require utilities' TEPs to seek to minimize costs and maximize benefits to all ratepayers and to be assessed for cost-benefit along a defined set of criteria. These assessments generally start with a scenario analysis to consider different EV deployment scenarios (such as that conducted by Xcel Colorado).[24] After this initial forecast, BCAs may include as benefits estimated revenue from charging, expected state and federal incentives, any customer contributions under

[17] Massachusetts Electric Company and Nantucket Electric Company each D/B/A National Grid, "Direct Pre-Filed Testimony of the Electric Vehicle Program Panel. Exhibit NG-EVPP-1," July 2021, available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/13758106.

[18] New York Department of Public Service, Matter Number 18-E-0138, "Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs," July 2020, available at https://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=249404&MatterSeq=56005.

[19] Massachusetts Electric Company and Nantucket Electric Company each D/B/A National Grid, "Responses to Attorney General's Second Set of Information Requests: Exhibit AG 2-3," November 2021, available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/14193298.

[20] 2019 Colo. Sess. Laws 3433–3437, available at https://leg.colorado.gov/sites/default/files/documents/2019A/bills/sl/2019a_sl_383.pdf.

[21] Illinois Electric Vehicle Act, 20 ILCS 627/1–627/99, available at https://www.ilga.gov/legislation/ilcs/ilcs3.asp?ActID=3348&ChapterID=5.

[22] 2023 Minnesota Statutes § 216B.1614, available at https://www.revisor.mn.gov/statutes/cite/216B.1614.

[23] Minnesota Public Utilities Commission, E-999/CI-17-879, "Order Making Finding and Requiring Filings: In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure," February 2019, available at https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId=%7B10BBAA68-0000-C413-9799-DF3ED0978E75%7D&documentTitle=20192-149933-01.

[24] Colorado Xcel Energy, "Transportation Electrification Plan: 2021 – 2023," available at https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/20A-0204E-_2021-2023_TEP_Updated.pdf.

Contribution in Aid of Construction ("CIAC") policies, estimates of the number of chargers required to support the anticipated EV adoption, charger utilization rates (over time), expected increases in load, and societal benefits such as reduced greenhouse gas emissions or economic benefits. As costs, BCAs may include installation costs and estimated power supply costs. It is important, given that the BCA will likely determine the amount of revenue available for use on program elements such as rebates, make-ready infrastructure, or education, that these costs and benefits are appropriately and completely accounted for.

**Q. Did the Company conduct a BCA to quantify the benefits of the EV programs to customers?**

A. Yes. Witness Myrom presents a workpaper (Exhibit A-153, JAM-3) which shows the costs and revenues from the EV programs from 2025 to 2031. As stated by witness Myrom,

> The positive and increasing values in each year clearly show that the additional load growth from EVs creates margin that exceeds the TEPs revenue requirement and other costs. Thus, the TEPs do not increase rates but instead create downward rate pressure for all customers while optimizing EV load.[25]

In this analysis, the Company compared revenue from EV charging with the costs of the EV programs as well as the costs of energy, capacity, transmission, and distribution related to the programs.[26]

[25] Myrom Direct, p. 4.

[26] Myrom Direct, Exhibit A-153.

**Q. In the BCA, how did the Company estimate EV adoption growth?**

A. According to witness Myrom, the Company anticipates EV adoption in its territory to range from 500,000 EVs (as modeled in the Company's 2021 IRP) to 630,000 EVs (as modeled by McKinsey for the Company) by 2030.[27] Critically, as noted by witness Myrom, "EV adoption and factory developments remain on track" within this range in deployment.[28]

**Q. Do you agree with these EV adoption estimates?**

A. I believe it is most important that, as noted by witness Myrom, the Company has observed that current EV adoption rates are aligned with its previous models of EV deployment. This indicates that the models used and estimates made by the Company are accurate and bearing out in the actual observed deployment of EVs.

It is also important to recognize that despite some recent public news articles, EV adoption continues to increase and long-term forecasts of EV adoption continue to predict strong future growth. In 2011, nationwide, EVs accounted for 0.2% of car sales.[29] This increased by 23 times to 4.6% of car sales in 2021.[30] Over the same time period, EVs deployed on

[27] Myrom Direct, p. 6.

[28] Myrom Direct, p. 6.

[29] Colato, J. and Ice, L., "Charging into the future: the transition to electric vehicles," February 2023, U.S. Bureau of Labor Statistics, available at https://www.bls.gov/opub/btn/volume-12/charging-into-the-future-the-transition-to-electric-vehicles.htm.

[30] *Ibid.*

the road increased from 22,000 to 2.2 million.[31, 32] Since then, this upward trend has continued. By 2027, sales of internal combustion engine vehicles are projected to be 29% lower than their 2017 peak.[33] According to Bloomberg Green, six of the ten biggest EV makers in the U.S. saw much higher sales in the first quarter of 2024 than in the first quarter of 2023.[34, 35] In fact, sales were up by 56% for Hyundai-Kia and 86% for Ford Motor Company.[36, 37] In the second quarter of 2024, Ford sales were up 61% over second quarter sales for 2023.[38] It is true that early in 2024, a lack of new models and delays in new vehicles slowed the pace of increasing sales for some companies, including Tesla and General Motors ("GM"). However, GM appears to be poised to lead and drive EV growth in the U.S. for the rest of the year given improvements in its new line of batteries.[39] In fact,

[31] *Ibid.*

[32] International Energy Agency, "Global EV Data Explorer," accessed August 21, 2024, available at https://www.iea.org/data-and-statistics/data-tools/global-ev-data-explorer.

[33] Bloomberg New Energy Finance, *Electric Vehicle Outlook 2024*," June 12, 2024, available at https://assets.bbhub.io/professional/sites/24/847354_BNEF_EVO2024_ExecutiveSummary.pdf.

[34] Randall, T., *Bloomberg Green*, "The Slowdown in US Electric Vehicle Sales Looks More Like a Blip," May 28, 2024, available at https://www.bloomberg.com/news/articles/2024-05-28/the-slowdown-in-us-electric-vehicle-sales-looks-more-like-a-blip.

[35] Alliance for Automotive Innovation, "Alliance for Automotive Innovations Reports New U.S. Electric Vehicle Data," July 2, 2024, available at https://www.autosinnovate.org/posts/press-release/2024-q1-get-connected-press-release.

[36] Randall, T., *Bloomberg Green*, "The Slowdown in US Electric Vehicle Sales Looks More Like a Blip," May 28, 2024, available at https://www.bloomberg.com/news/articles/2024-05-28/the-slowdown-in-us-electric-vehicle-sales-looks-more-like-a-blip.

[37] Cox Automotive, "Cox Automotive 2024 Path to EV Adoption Study Suggests Electric Vehicle Consideration Will Surge in Second Half of Decade," May 14, 2024, available at https://www.coxautoinc.com/news/cox-automotive-2024-path-to-ev-adoption-study-suggests-electric-vehicle-consideration-will-surge-in-second-half-of-decade/.

[38] Johnson, P., *Electrek*, "Ford's EV sales surge in Q2, topping GM for second in the US EV market behind Tesla," July 3, 2024, available at https://electrek.co/2024/07/03/fords-ev-sales-surge-q2-close-gap-with-tesla/.

[39] Randall, T., *Bloomberg Green*, "The Slowdown in US Electric Vehicle Sales Looks More Like a Blip," May 28, 2024, available at https://www.bloomberg.com/news/articles/2024-05-28/the-slowdown-in-us-electric-vehicle-sales-looks-more-like-a-blip.

in the second quarter of 2024, GM sales were up 40% over the second quarter of 2023 and 34% over the first quarter of 2024.[40]

According to a July 26, 2024 report from J.D. Power, although premium segment retail sales of EVs are down 13% -- driven by Tesla's 22% decline in sales – the mass market segment is up 63%.[41] Despite more stringent guidance on domestic content and new model eligibility requirements, across the U.S., new EV registrations increased by more than 40% in 2023 compared to 2022.[42] Furthermore, given that leased vehicles are now eligible for federal tax credits, the rate of adoption is expected to continue increasing.[43] In Michigan, according to a report by the Alliance for Automotive Innovation, EV market penetration has reached 4%, which is up from 3.4% in 2023 and 2.13% in 2021, indicating a marked and consistent increase in EV adoption.[44]

Long-term forecasts of EV sales also indicate strong expected future growth. With more education around EVs and EV charging, infrastructure development, and technological innovations, a recent study found that 80% of today's EV skeptics will consider the

[40] Hogan, M., *Inside EVs*, "General Motors Sold a Record Number of EVs in Q2 2024," July 2, 2024, available at https://insideevs-com.cdn.ampproject.org/c/s/insideevs.com/news/725293/gm-ev-sales-q2-2024/amp/.

[41] J.D. Power, "July SAAR reaches 16.7 Million – Highest in More Than Three Years," July 26, 2024, available at https://www.jdpower.com/business/press-releases/jd-power-globaldata-automotive-forecast-july-2024.

[42] International Energy Agency, "Global EV Outlook 2024," April 2024, available at https://www.iea.org/reports/global-ev-outlook-2024.

[43] *Ibid.*

[44] Alliance for Automotive Innovation, "Get Connected: Electric Vehicle Quarterly Report," 2023, available at https://www.autosinnovate.org/posts/papers-reports/Get%20Connected%20EV%20Quarterly%20Report%202023%20Q4.pdf.

purchase of an EV in the next decade.[45] The International Energy Agency estimated in its "Global EV Outlook 2024," published in April 2024, that with stated policies in place, U.S. sales of battery electric vehicles ("BEVs") are projected to increase to 2.5 million sold in 2025 (up from 1.1 million sold in 2024).[46, 47] In fact, a 2024 Environmental Defense Fund study showed that actual EV sales in 2023 outperformed 85% of expert forecasts from 2019 to 2022.[48]

**Q. How is public charging infrastructure critical to ensuring these EV adoption rates and the subsequent benefits?**

A. Given that a large portion of EV charging occurs at home, a significant portion of the Company's revenue projections from EV charging also likely come from home charging. In fact, according to the Company's 2024 TEP, 70% of charging currently occurs at home and 30% occurs at public charging stations in the Company's territory.[49] However, it has been well documented that range anxiety and a perceived lack of public charging

[45] Cox Automotive, "Cox Automotive 2024 Path to EV Adoption Study Suggests Electric Vehicle Consideration Will Surge in Second Half of Decade," May 14, 2024, available at https://www.coxautoinc.com/news/cox-automotive-2024-path-to-ev-adoption-study-suggests-electric-vehicle-consideration-will-surge-in-second-half-of-decade/.

[46] International Energy Agency, "Global EV Outlook 2024," April 2024, available at https://www.iea.org/reports/global-ev-outlook-2024.

[47] Recurrent, "2024 Data: EV Adoption is Still on Pace in the US," July 10, 2024, available at https://www.recurrentauto.com/research/ev-adoption-us.

[48] Environmental Defense Fund, "Electric vehicle sales are going further, faster than experts predicted," March 2024, available at https://www.edf.org/sites/default/files/2024-03/Actual%202023%20EV%20sales%20compared%20to%20forecasts.pdf.

[49] Consumers Energy Company's Transportation Electrification Plan 2024, Case No. U-21538, p. 8.

infrastructure is a primary concern for potential EV buyers.[50, 51, 52, 53, 54, 55, 56, 57, 58, 59, 60, 61] According to a 2023 study from the University of Chicago's Energy Policy Institute and the Associated Press-NORC Center for Public Affairs Research, the most commonly cited reasons survey respondents gave to not purchase an EV were the high upfront cost of the

[50] S&P Global: Mobility, "Affordability tops charging and range concerns in slowing EV demand," November 2023, available at https://www.spglobal.com/mobility/en/research-analysis/affordability-tops-charging-and-range-concerns-in-slowing-ev-d.html.

[51] EV Charging Summit, "10 Biggest Challenges Facing the EV industry Today," January 2023, available at https://evchargingsummit.com/blog/challenges-facing-the-ev-industry-today/.

[52] Bloomberg, "Despite Hurdles, Vehicle Electrification in the US is Likely Here to Stay, finds Bloomberg Intelligence," April 2024, available at https://www.bloomberg.com/company/press/despite-hurdles-vehicle-electrification-in-the-us-is-likely-here-to-stay-finds-bloomberg-intelligence/.

[53] De Prez, M., *Fleet News*, "Kia drives the shift towards EV uptake," April 2019, available at https://www.fleetnews.co.uk/fleet-management/case-studies/industry-profiles/kia-motors-uk.

[54] Tang, R., Blair, M. and Alizamir, S., "Two-Sided Subsidies for Electric Vehicles: The Role of Regional Characteristics," June 2024, available at https://ssrn.com/abstract=4857253.

[55] Avery, R., *TomTom*, "Forget worrying about range, charging anxiety is now the prime concern for EV drivers," September 2023, available at https://www.tomtom.com/newsroom/behind-the-map/charging-anxiety-for-ev-drivers/.

[56] Daly, M. and Sanders, L., *PBS News*, "AP-NORC/EPIC poll shows Americans are still hesitant about electric vehicles, despite Biden's push," June 2024, available at https://www.pbs.org/newshour/politics/ap-norc-epic-poll-shows-americans-are-still-hesitant-about-electric-vehicles-despite-bidens-push.

[57] Southern California Edison Company, "Application of Southern California Edison Company (U338E) for Approval of its Charge Ready 2 Infrastructure and Market Education Programs," Application 18-06-015, September 2020, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M346/K230/346230115.PDF.

[58] Illinois Commonwealth Edison, "ComEd Beneficial Electrification Plan," 2022, available at https://icc.illinois.gov/docket/P2022-0432/documents/325766/files/567114.pdf.

[59] Massachusetts Electric Company and Nantucket Electric Company each D/B/A National Grid, "Direct Pre-Filed Testimony of the Electric Vehicle Program Panel," Exhibit NG-EVPP-1, July 2021, available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/13758106.

[60] Minnesota Xcel Energy, "Petition of Northern States Power Company for Approval of a Public Charging Network, an Electric School Bus Pilot, and Program Modifications," 2022, available at https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={90B25F82-0000-C32B-B70E-1C25A3E2A491}&documentTitle=20228-188061-07.

[61] Consolidated Edison Company of New York, Inc., "Electric Vehicle Infrastructure Make-Ready Program Implementation Plan," Case 18-E-0138, September 2020, available at https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b181AB1C0-0F11-44F6-B652-5705D91EC1B3%7d.

vehicle and charging station availability.[62] Given these concerns, it is no surprise that the existence of public EV charging stations directly enables customers to purchase EVs,[63, 64, 65, 66] leading to significant at-home charging and revenue from electricity sales. [67, 68, 69, 70, 71] However, in the first quarter of 2024, despite an 8% increase in EVs on the road in the

[62] Energy Policy Center, University of Chicago and Associated Press-NORC Center for Public Affairs Research,. "New Poll: 2 in 5 Would Consider Purchasing An Electric Vehicle As Their Next Car, But They Remain Prohibitively Expensive for Americans," April 10, 2023, available at https://epic.uchicago.edu/news/new-poll-2-in-5-would-consider-purchasing-an-electric-vehicle-as-their-next-car-but-they-remain-prohibitively-expensive-for-americans/.

[63] Osaka, S., *The Washington Post*, "For each public charger, here's how many EVs are looking to plug in," May 2024, available at https://www.washingtonpost.com/climate-solutions/2024/05/20/charging-stations-lag-ev-sales/.

[64] Center for Sustainable Energy, "The State of Electric Vehicle Adoption in the U.S. and the Role of Incentives in Market Transformation," September 2023, available at https://energycenter.org/thought-leadership/blog/state-electric-vehicle-adoption-us-and-role-incentives-market#:~:text=Publicly%20available%20EV%20charging%20inspires,apartments%2C%20to%20charge%20an%20EV.

[65] U.S. Department of Energy, Alternative Fuels Data Center, "Charging Electric Vehicles in Public," accessed June 2024, available at https://afdc.energy.gov/fuels/electricity-charging-public.

[66] International Energy Agency, "Global EV Outlook 2024: Moving towards increased affordability," 2024, available at https://iea.blob.core.windows.net/assets/a9e3544b-0b12-4e15-b407-65f5c8ce1b5f/GlobalEVOutlook2024.pdf.

[67] Nadel, S., American Council for an Energy-Efficient Economy (ACEEE). "Charging Ahead: How EVs Could Drive Down Electricity Rates," January 2024.

[68] Metz, L. et al., Synapse Energy Economics, Inc., "Distribution System Investments to Enable Medium- and Heavy-Duty Vehicle Electrification: A Case Study of New York," April 2023, available at https://acrobat.adobe.com/id/urn:aaid:sc:US:3ef62d18-a652-4848-a2a5-15eb2771d8cc.

[69] Synapse Energy Economics, Inc., "EVs Are Driving Rates Down for All Customers: State-by-State Cumulative EV Net Rate Impact Summary," June 2024, available at https://www.synapse-energy.com/sites/default/files/EV%20All%20State%20List%20PDF_0.pdf.

[70] Satchwell, A. et al., Prepared for the U.S. Department of Energy, "Quantifying the Financial Impacts of Electric Vehicles on Utility Ratepayers and Shareholders," February 2023, available at https://eta-publications.lbl.gov/sites/default/files/ev_financial_impacts_final_report_final_draft_02092023.pdf.

[71] California Public Utilities Commission, "Utility Cost and Affordability of the Grid of the Future: An Evaluation of Electric Costs, Rates, and Equity Issues Pursuant to P.U. Code Section 913.1. 2021," available at: https://www.cpuc.ca.gov/-/media/ cpuc-website/divisions/office-of-governmental-affairs-division/reports/2021/senate-bill-695-report-2021-and-en-bancwhitepaper_final_04302021.pdf.

U.S, the number of publicly available EV chargers increased only 5%.[72] Furthermore, as of the fourth quarter of 2023, although Michigan's ratio of 12.6 EVs per public charging port[73, 74] only slightly exceeds the optimal ratio of 8 to 12 EVs per port,[75] as EV adoption continues to increase, EV drivers may have difficulty accessing public charging.[76] Failure to meet this demand could therefore have the adverse effect of slowing adoption, resulting in stagnant or reduced revenues from EV charging.[77]

**Q: What is the economic value of EV charging and how can it be leveraged to support EV adoption and its subsequent benefits?**

A. According to a Synapse Energy Economics study examining the revenues and costs associated with EVs between 2011 and 2021, EV drivers have contributed about $18

[72] Alliance for Automotive Innovation, "Alliance for Automotive Innovations Reports New U.S. Electric Vehicle Data," July 2, 2024, available at https://www.autosinnovate.org/posts/press-release/2024-q1-get-connected-press-release.

[73] Alternative Fuels Data Center, "Electric Vehicle Registrations by State," accessed August 21, 2024, available at https://afdc.energy.gov/data/10962.

[74] Alternative Fuels Data Center, "EV Charging Ports by State," accessed August 21, 2024, available at https://afdc.energy.gov/data/10366.

[75] Lowery, L., "Interactive index show how each U.S. state measures up in EV charging," *Repairer Driven* News, September 12, 2023, available at https://www.repairerdrivennews.com/2023/09/12/interactive-index-show-how-each-u-s-state-measures-up-in-ev-charging/#:~:text=Eight%20to%2012%20EVs%20per,to%20analysis%20from%20SBD%20Automotive.

[76] Bestvater, S. and Shah, S., Pew Research Center, "Electric Vehicle Charging Infrastructure in the U.S," May 2024, available at https://www.pewresearch.org/data-labs/2024/05/23/electric-vehicle-charging-infrastructure-in-the-u-s/.

[77] *Ibid.*

million more than their associated costs in each of Illinois[78] and Virginia,[79] $26.7 million more in Colorado,[80] and $85.3 million more in New Jersey.[81] In Colorado[82] and New Jersey,[83] when utility expenditures on EV programs are included in costs, the net revenue still exceeds costs by approximately $15.7 and $62.7 million, respectively. Reinvestment of a portion of these revenues from EV charging back into EV programs can accelerate public charging infrastructure development, thus enabling greater EV deployment and increased downward rate pressures for all ratepayers over time.

[78] Shenstone-Harris, S. et al., *Synapse Energy Economics, Inc*., "Electric Vehicles are Driving Rates Down for All Customers, State Factsheet: Illinois," April 2024, available at https://www.synapse-energy.com/sites/default/files/Electric Vehicles Are Driving Rates Down for All Customer Illinois May 2024.pdf.

[79] Shenstone-Harris, S. et al., *Synapse Energy Economics, Inc*., "Electric Vehicles are Driving Rates Down for All Customers, State Factsheet: Virginia," April 2024, available at https://www.synapse-energy.com/sites/default/files/Electric Vehicles Are Driving Rates Down for All Customer Virginia May 2024 24-023.pdf.

[80] Shenstone-Harris, S. et al., *Synapse Energy Economics, Inc*., "Electric Vehicles are Driving Rates Down for All Customers, State Factsheet: Colorado," April 2024, available at https://www.synapse-energy.com/sites/default/files/Electric%20Vehicles%20Are%20Driving%20Rates%20Down%20for%20All%20Customer%20Colorado%20May%202024.pdf.

[81] Shenstone-Harris, S. et al., *Synapse Energy Economics, Inc*., "Electric Vehicles are Driving Rates Down for All Customers, State Factsheet: New Jersey," April 2024, available at https://www.synapse-energy.com/sites/default/files/Electric%20Vehicles%20Are%20Driving%20Rates%20Down%20for%20All%20Customer%20New%20Jersey%20April%202024.pdf

[82] Shenstone-Harris, S. et al., *Synapse Energy Economics, Inc*., "Electric Vehicles are Driving Rates Down for All Customers, State Factsheet: Colorado," April 2024, available at https://www.synapse-energy.com/sites/default/files/Electric%20Vehicles%20Are%20Driving%20Rates%20Down%20for%20All%20Customer%20Colorado%20May%202024.pdf.

[83] Shenstone-Harris, S. et al., *Synapse Energy Economics, Inc*., "Electric Vehicles are Driving Rates Down for All Customers, State Factsheet: New Jersey," April 2024, available at https://www.synapse-energy.com/sites/default/files/Electric%20Vehicles%20Are%20Driving%20Rates%20Down%20for%20All%20Customer%20New%20Jersey%20April%202024.pdf

**Q. Do you have any concerns with the Company's BCA?**

A. Not in this case, but in the future, I am hopeful that the Company will include more of the benefits from EVs in its BCA. As indicated by witness Myrom in a discovery response in this case (Exhibit MEIU-2 (LSS-2)),

> The cost test shows that the TEP customer programs do not increase rates but instead create downward rate pressure for all customers while optimizing EV load. In fact, there is significant additional margin from optimized EV load growth, even without considering other potential non-rate benefits such as, but not limited to, equitable access to charging, economic development, job creation impacts, and reduced pollution and health impacts.

**Q. Do you agree with witness Myrom about the additional benefits of EV programs?**

A. Yes. I agree that EV programs provide societal benefits including reduced greenhouse gas emissions, reduced criteria pollutant emissions, reduced noise pollution, reduced transportation fuel costs, improved physical and mental health, job creation, and economic impacts.[84, 85, 86, 87, 88]

[84] American Council for an Energy-Efficient Economy, "Cost-Effectiveness Tests: Overview of State Approaches to Account for Health and Environmental Benefits of Energy Efficiency," December 2018, available at https://www.aceee.org/sites/default/files/he-ce-tests-121318.pdf.

[85] U.S. Department of Transportation, "Benefits to Communities," available at https://www.transportation.gov/rural/ev/toolkit/ev-benefits-and-challenges/community-benefits#:~:text=BEVs%20run%20with%20zero%20tailpipe,businesses%20and%20provide%20health%20benefits.

[86] U.S. Department of Transportation, "Community Benefits of Urban Mobility Electrification," available at https://www.transportation.gov/urban-e-mobility-toolkit/e-mobility-benefits-and-challenges/community-benefits.

[87] U.S. Department of Energy, "Alternative Fuels Data Center. Emissions from Electric Vehicles," available at https://afdc.energy.gov/vehicles/electric-emissions.

[88] Armstrong, S., *The London Evening Standard*, "Killing the Roar: Electric Vehicles Can Calm Us Down," July 2022, available at https://www.standard.co.uk/optimist/plug-it-in/electric-vehicles-duncan-williams-noise-sound-b1010886.html.

**Q. How have these societal benefits been quantified?**

A. A number of these societal benefits,[89] including reduced greenhouse gas emissions and reduced criteria pollutant emissions,[90] can be accurately quantified. Among the TEPs that I reviewed, ComEd,[91] Xcel Minnesota,[92] Xcel Colorado,[93] and Ameren[94] each used the Federal Social Cost of Carbon ("SCC") developed by an interagency working group ("IWG") to calculate the benefits of carbon dioxide ("$CO_2$") reductions associated with transportation electrification.

**Q. What is the SCC and how was it developed?**

A. Federal Executive Order 12866, issued in 1993, required Federal agencies to assess the costs and benefits of proposed regulations.[95] Following a court ruling in 2008, the SCC has

[89] American Council for an Energy-Efficient Economy, "Cost-Effectiveness Tests: Overview of State Approaches to Account for Health and Environmental Benefits of Energy Efficiency," December 2018, available at https://www.aceee.org/sites/default/files/he-ce-tests-121318.pdf.

[90] Interagency Working Group on Social Cost of Greenhouse Gases, "Social Cost of Carbon, Methane, and Nitrous Oxide-Interim Estimates Under Executive Order 13990," February 2021, available at https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.

[91] Illinois Commonwealth Edison, "ComEd Beneficial Electrification Plan," 2022, available at https://icc.illinois.gov/docket/P2022-0432/documents/325766/files/567114.pdf.

[92] Minnesota Xcel Energy, "Petition of Northern States Power Company for Approval of a Public Charging Network, an Electric School Bus Pilot, and Program Modifications," 2022, available at https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={90B25F82-0000-C32B-B70E-1C25A3E2A491}&documentTitle=20228-188061-07.

[93] Xcel Colorado Energy, "Benefit-Cost Analysis of Transportation Electrification in the Xcel Energy Colorado Service Territory," May 2020, available at https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=926529&p_session_id=.

[94] Ameren Illinois Company, "Beneficial Electrification Plan," 2022, available at https://www.icc.illinois.gov/docket/P2022-0431/documents/325722/files/567031.pdf.

[95] The White House, Executive Order 12866, September 1993, available at https://www.archives.gov/files/federal-register/executive-orders/pdf/12866.pdf.

also been incorporated into these Federal agency benefit-cost analyses.[96] To ensure accuracy and consistency across agencies, in 2009, the IWG was established and the first SCC estimates were published in 2010.[97] In 2016, the IWG published estimates of the social costs of two additional greenhouse gases: methane and nitrous oxide.[98] Together, the sum of the social costs of $CO_2$, methane, and nitrous oxide represent the total social cost of greenhouse gas emissions. Although it is therefore possible to calculate the total cost of all greenhouse gas emissions, in my review, it currently appears more common for utilities to quantify only the social cost of $CO_2$ emissions.

The SCC itself represents an estimate of the monetized net economic damages associated with an increase of one metric ton of $CO_2$ emissions.[99] There are several important modeling choices and assumptions that influence this estimate and introduce uncertainty, including a determination of how much weight to place on future impacts (called the "discount rate"). A high discount rate indicates that future impacts are less significant than

[96] In 2008, the Center for Biological Diversity brought a case against the National Highway Traffic Safety Administration ("NHTSA") to the 9th Circuit Court over a proposed rule to establish the corporate average fuel economy ("CAFÉ") standards for light duty trucks, minivans, and some sport utility vehicles. The Court ruled that the NHTSA's Environment Assessment of these vehicle classes failed to adequately quantify the expected $CO_2$ emissions and assess the resulting environmental impact. *See* Center for Biological Diversity v. National Highway Traffic Safety Admin., 538 F.3d 1172, 1200 (9th Cir. 2008), available at https://elaw.org/resource/ctr-biol-diversity-v-natl-hwy-transp-safety-bd-538-f3d-1172-9th-cir-2008.

[97] Interagency Working Group on Social Cost of Greenhouse Gases, "Social Cost of Carbon, Methane, and Nitrous Oxide-Interim Estimates Under Executive Order 13990," February 2021, available at https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.

[98] *Ibid.*

[99] *Ibid.*

current impacts, whereas a low discount rate suggests that future impacts are equally significant to current impacts.[100] According to the IWG,

> . . . new data and evidence strongly suggests that the discount rate regarded as appropriate for intergenerational analysis is lower [than 2.5%].[101]

**Q. How can these calculations be related to a utility TEP?**

A. Greenhouse gas emissions reductions can be quantified by comparing the difference between emissions from EV charging (i.e., based on emissions related to electricity generation) and emissions from internal combustion engine vehicles.[102, 103] This difference can then be converted into a cost of avoided emissions using an SCC. The federal SCC has been regularly updated to reflect new findings and has been recognized by federal agencies,

[100] Resources for the Future, "Social Cost of Carbon 101," available at https://www.rff.org/publications/explainers/social-cost-carbon-101/.

[101] Interagency Working Group on Social Cost of Greenhouse Gases. Social Cost of Carbon, Methane, and Nitrous Oxide-Interim Estimates Under Executive Order 13990. February 2021. Available at https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.

[102] California Public Utilities Commission, "Pacific Gas and Electric Company 2017 General Rate Case Phase II Updated and Amended Prepared Testimony," Exhibit (PG&E-9) Volume 1 Marginal Costs, 2016, available at https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A1606013/319/170773573.pdf.

[103] Energy & Environmental Economics, "Technical Potential for Local Distributed Photovoltaics in California," 2012, available at https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_website/content/utilities_and_industries/energy/reports_and_white_papers/ldpvpotentialreportmarch2012.pdf.

state legislatures[104, 105, 106] and public utility commissions[107, 108, 109, 110] alike as the best mechanism to quantify the social costs of $CO_2$ emissions and, therefore, the social benefits of reduced emissions. For example, in 2018, the Illinois General Assembly passed Public Act 102-0662, which states that

> The Social Cost of Carbon is $16.50 per megawatt hour, which is based on the U.S. Interagency Working Group on Social Cost of Carbon's price in August 2016 Technical Update using a 3% discount rate, adjusted for inflation for each year of the program. Beginning with the delivery year commencing June 1, 2023, the price per megawatt hour shall increase by $1 per megawatt hour, and continue to increase by an additional $1 per megawatt hour each delivery year thereafter.[111]

Also in 2018, the Minnesota Public Utilities Commission ("MN PUC") issued an order (E-999/CI-14-643) that finalized $CO_2$ and criteria pollutant cost estimates to be used by utilities in conducting scenario analyses, evaluating programs, and selecting resource

[104] See NJ REV. STAT. § 48:3-87.3(8).

[105] See 220 ILCS 3855/1-75(d-5)(1)(B)(i).

[106] 2019 Colo. Sess. Laws 3290, available at https://leg.colorado.gov/sites/default/files/documents/2019A/bills/sl/2019a_sl_359.pdf.

[107] Public Utilities Commission of the State of California, Decision 19-05-019, "Decision Adopting Cost-Effectiveness Analysis Framework Policies for all Distributed Energy Resources," May 2019, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M293/K833/293833387.PDF.

[108] Minnesota Public Utilities Commission, E-999/CI-14-643, "In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minnesota Statutes Section 216B.2422, Subdivision 3," January 2018, available at https://costofcarbon.org/files/MPUC_E-999_CI-14-643.pdf.

[109] Public Utilities Commission of Nevada, Docket No. 17-07020, "Investigation and rulemaking to implement Senate Bill 65 (2017)," August 2018, available at https://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2017-7/32153.pdf.

[110] New York Independent System Operator (NYISO), "Carbon Pricing Draft Recommendations: A Report Prepared for the Integrating Public Policy Task Force," August 2018, available at https://www.nyiso.com/documents/20142/2179214/Carbon%20Pricing%20Draft%20Recommendations%20201808 02.pdf/575a6d2b-ad09-d8f8-e566-39a0c04f9a43.

[111] 220 ILCS 3855/1-75(d-5)(1)(B)(i).

options.[112] To do this, the MN PUC conducted integrated assessment models consistent with those used by the IWG. The MN PUC determined that it would adopt a range of cost estimates for $CO_2$ emissions, with the low end reflecting the global damage of the last marginal short ton calculated through 2100 at a 5 percent discount rate and the high end reflecting the global damage of the last marginal short ton calculated through 2300 at a 3 percent discount rate.[113] Overall, the MN PUC determined that the cost of $CO_2$ emissions to be used by utilities in conducting analyses is $33.52 per metric ton of carbon.

The MN PUC also estimated the costs of other criteria pollutants, using ranges in emissions for small particulate matter ("$PM_{2.5}$"), nitrous oxides ("$NO_x$"), and sulfur dioxide ("$SO_2$") production over time in rural, metropolitan fringe, and urban areas, with a cost of $2,014 per ton for each criteria pollutant.[114]

[112] Minnesota Public Utilities Commission, E-999/CI-14-643, "In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minnesota Statutes Section 216B.2422, Subdivision 3," January 2018, available at https://costofcarbon.org/files/MPUC_E-999_CI-14-643.pdf.

[113] *Ibid.*

[114] Minnesota Public Utilities Commission, E-999/CI-14-643, "In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minnesota Statutes Section 216B.2422, Subdivision 3," January 2018, available at https://costofcarbon.org/files/MPUC_E-999_CI-14-643.pdf.

**Q. How have public utilities quantified the avoided greenhouse gas and criteria pollutant emissions associated with EVs in their service territories?**

A. As discussed above, among the TEPs that I reviewed, ComEd,[115] Xcel Minnesota,[116] Xcel Colorado,[117] and Ameren[118] each used the federal SCC developed by the IWG to calculate the social benefits of $CO_2$ reductions associated with transportation electrification.

In accordance with Illinois Public Act 102-0662,[119] in their 2022 TEPs, ComEd and Ameren monetized the cost of $CO_2$ emissions based on the IWG's SCC at a 3 percent discount rate, assuming a societal impact of $CO_2$ emissions of $51 per metric ton.[120] To assess the benefit of avoided emissions, Ameren, for example, calculated the difference between the expected increase in $CO_2$ emissions due to increased transportation electrification (1,033 pounds of $CO_2$ per kWh of increased load) and expected $CO_2$ emissions (absent transportation electrification) in pounds of carbon per MMBtu of

[115] Illinois Commonwealth Edison, "ComEd Beneficial Electrification Plan," 2022, available at https://icc.illinois.gov/docket/P2022-0432/documents/325766/files/567114.pdf.

[116] Minnesota Xcel Energy, "Petition of Northern States Power Company for Approval of a Public Charging Network, an Electric School Bus Pilot, and Program Modifications," 2022, available at https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={90B25F82-0000-C32B-B70E-1C25A3E2A491}&documentTitle=20228-188061-07.

[117] Xcel Colorado Energy, "Benefit-Cost Analysis of Transportation Electrification in the Xcel Energy Colorado Service Territory," May 2020, available at https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=926529&p_session_id=.

[118] Ameren Illinois Company, "Beneficial Electrification Plan," 2022, available at https://www.icc.illinois.gov/docket/P2022-0431/documents/325722/files/567031.pdf.

[119] Illinois General Assembly, Public Act 102-0662 (SB 2408), Article 5: Energy Transition, February 2020, available at https://www.ilga.gov/legislation/publicacts/102/PDF/102-0662.pdf.

[120] Illinois Commonwealth Edison, "ComEd Beneficial Electrification Plan," 2022, available at https://icc.illinois.gov/docket/P2022-0432/documents/325766/files/567114.pdf.

gasoline and diesel fuel.[121] This difference in emissions was then converted to a cost using the SCC. Emissions of criteria pollutants ($PM_{2.5}$ and $NO_x$), were calculated for different transportation electrification scenarios based on Argonne National Laboratory's Alternative Fuel Life-Cycle Environmental and Economic Transportation ("AFLEET") Tool.[122, 123] Ameren also applied an emissions factor to all of the emissions cost calculations attributed to low-income ("LI") areas to account for the increased impact that emissions have on environmental justice communities.[124]

In another example, Xcel Minnesota[125] and Xcel Colorado[126] similarly calculated avoided $CO_2$ emissions from fewer internal combustion engine vehicles based on 0.0085 metric tons per gallon of gasoline and 0.01098 metric tons per gallon of diesel emissions. Carbon dioxide emissions from EVs were calculated based on charging load shapes and the resulting hourly emissions for electricity production.[127] In accordance with the MN PUC

[121] Illinois Commerce Commission, Direct Testimony of Andrew Cottrell, Applied Energy Group, Inc., June 2022, available at https://www.icc.illinois.gov/docket/P2022-0431/documents/325722/files/567037.pdf.

[122] *Ibid.*

[123] U.S. Department of Energy, Argonne National Laboratory, "AFLEET Tool," available at https://afleet.es.anl.gov/home/.

[124] Illinois Commerce Commission, Direct Testimony of Andrew Cottrell, Applied Energy Group, Inc., June 2022, available at https://www.icc.illinois.gov/docket/P2022-0431/documents/325722/files/567037.pdf.

[125] Minnesota Xcel Energy, "Petition of Northern States Power Company for Approval of a Public Charging Network, an Electric School Bus Pilot, and Program Modifications," 2022, available at https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={90B25F82-0000-C32B-B70E-1C25A3E2A491}&documentTitle=20228-188061-07.

[126] Xcel Colorado Energy, "Benefit-Cost Analysis of Transportation Electrification in the Xcel Energy Colorado Service Territory," May 2020, available at https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=926529&p_session_id=.

[127] Minnesota Xcel Energy, "Petition of Northern States Power Company for Approval of a Public Charging Network, an Electric School Bus Pilot, and Program Modifications," 2022, available at

order,[128, 129] Xcel Minnesota then converted avoided emissions to costs based on a weighted average of the types of vehicles (i.e., EVs versus internal combustion engine vehicles) in its service territory and the PUC's adopted cost of $CO_2$ emissions (i.e., $33.52 per metric ton of carbon).[130] Xcel Colorado, in accordance with Senate Bill ("SB") 19-236,[131, 132] converted avoided emissions to costs based on assumption of $46 per metric ton of carbon.[133]

https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={90B25F82-0000-C32B-B70E-1C25A3E2A491}&documentTitle=20228-188061-07.

[128] Minnesota Public Utilities Commission, Docket No. E-999/CI-14-463, "Order Updating Environmental Cost Values," January 2018, available at https://costofcarbon.org/files/MPUC_E-999_CI-14-643.pdf.

[129] The Minnesota Public Utility Commission Order Updating Environmental Cost Values adopts a range of environmental costs for $CO_2$ emissions defined by the IWG's SCC. This range allows for a value between the SCC with a 5.0% discount rate calculated through 2100, at the low end, and a 3.0% discount rate calculated through 2300, at the high end.

[130] Minnesota Xcel Energy, "Petition of Northern States Power Company for Approval of a Public Charging Network, an Electric School Bus Pilot, and Program Modifications," 2022, available at https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={90B25F82-0000-C32B-B70E-1C25A3E2A491}&documentTitle=20228-188061-07.

[131] Colorado Legislature, SB 19-236, April 2019, available at https://leg.colorado.gov/sites/default/files/2019a_236_signed.pdf.

[132] Colorado SB 19-236 requires public electric utilities to consider the social cost of carbon emissions based on the most recent assessment of the IWG's SCC. As of 2020, this cost could not be less than $46 per short ton. The Commission is permitted to modify the social cost of carbon based on escalation rates equal to or greater than the IWG's SCC.

[133] Xcel Colorado Energy, "Benefit-Cost Analysis of Transportation Electrification in the Xcel Energy Colorado Service Territory," May 2020, available at https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=926529&p_session_id=.

**Q. How have public utilities evaluated their programs and how have they incorporated these societal benefits into their BCAs?**

A. There are a number of common BCA practices used by utilities and public utility commissions to evaluate programs' benefits and costs. These include:[134]

- *Participant cost test ("PCT"):* This test evaluates the benefits and costs that a program has on its participants;
- *Ratepayer impact measure ("RIM"):* This test evaluates the benefits and costs that a program has on the rates paid by all customers. It includes lost utility revenues as a cost;
- *Utility cost test ("UCT"):* This test evaluates the benefits and costs a program has on the utility system;
- *Total resource cost test ("TRC"):* This test evaluates the benefits and costs that a program has on both the utility system and the program participants;
- *Societal cost test ("SCT"):* This test evaluates the impact that a program has on society as a whole; and
- *Jurisdiction-specific test ("JST"):* This test evaluates the impact that a program has on the utility system as well as its impact toward achieving relevant policy goals.

To fully capture the value of a utility TEP, it is important that utilities and public utility commissions evaluate not only the programs' financial impact on ratepayers and the utility system but also the broader benefits that accrue to society as a whole. These societal

[134] Shenot, J., Regulatory Assistance Project, "Using Benefit-Cost Analysis to Improve Distribution system Investment Decisions," November 2022, available at https://www.raponline.org/wp-content/uploads/2023/09/rap-shenot-prause-shipley-using-benefit-cost-analysis-issue-brief-2022-november.pdf.

benefits can be incorporated into utility TEPs by including the avoided costs in the overall financial analysis using a TRC, as was done by ComEd[135] and Ameren,[136] or by using an SCT. Utilities can also utilize more than one of these cost tests to evaluate the associated costs and benefits of their proposed programs, with one typically identified as the primary test for decision-making.[137, 138] In general, when multiple tests are performed, each is utilized in the overall BCA, but they are discussed individually to allow for separate evaluations of the benefits and costs to society, ratepayers, and participants. For example, in addition to a TRC, Ameren also conducted a RIM test, which, as described above, considers the cost-effectiveness of the plan from the ratepayer's perspective (i.e., without any additional societal benefits).[139] Similarly, Xcel Minnesota[140] and Xcel Colorado[141] also performed RIM tests, but supplemented these tests with a PCT to assess the costs and

[135] Illinois Commonwealth Edison, "ComEd Beneficial Electrification Plan," 2022, available at https://icc.illinois.gov/docket/P2022-0432/documents/325766/files/567114.pdf.

[136] Ameren Illinois Company, "Beneficial Electrification Plan," 2022, available at https://www.icc.illinois.gov/docket/P2022-0431/documents/325722/files/567031.pdf.

[137] Shenot, J., Regulatory Assistance Project, "Using Benefit-Cost Analysis to Improve Distribution system Investment Decisions," November 2022, available at https://www.raponline.org/wp-content/uploads/2023/09/rap-shenot-prause-shipley-using-benefit-cost-analysis-issue-brief-2022-november.pdf.

[138] National Energy Screening Project, "Database of Screening Practices (DSP)," available at https://www.nationalenergyscreeningproject.org/state-database-dsp/database-of-state-efficiency-screening-practices/.

[139] Ameren Illinois Company, "Beneficial Electrification Plan," 2022, available at https://www.icc.illinois.gov/docket/P2022-0431/documents/325722/files/567031.pdf.

[140] Xcel Energy Minnesota, "Petition of Northern States Power Company for Approval of a Public Charging Network, an Electric School Bus Pilot, and Program Modifications," 2022, available at https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={90B25F82-0000-C32B-B70E-1C25A3E2A491}&documentTitle=20228-188061-07.

[141] Xcel Energy Colorado, "Benefit-Cost Analysis of Transportation Electrification in the Xcel Energy Colorado Service Territory," May 2020, available at https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=926529&p_session_id=.

benefits realized by the vehicle driver or fleet owner, and an SCT test to evaluate the benefits and costs to society as a whole.

**Q. What do you recommend with respect to the Company's BCA?**

A. I recommend that, in the future, the Company should include in its BCA societal benefits including reduced greenhouse gas emissions, reduced criteria pollutant emissions, reduced noise pollution, reduced transportation fuel costs, improved physical and mental health, job creation, and economic impacts. To standardize this process, the Commission should conduct a study to either establish a process by which each utility can quantify these benefits in a standard manner (e.g., by establishing a methodology to calculate the monetary benefits of reduced $CO_2$ emissions) or determine an estimated overall societal benefit factor per EV or per kWh of charging that each utility can utilize.

## B. COMPANY EV CHARGING PROGRAMS

**Q. What changes to its EV charging programs does the Company propose?**

A. The Company does not propose any additional spending for its EV charging programs. According to witness Myrom, the Company proposes six "enhancements to further support customers and load management," which are, in summary:

> (1) The adoption of the North American Charging Standard ("NACS") wherever a J-1772 or Combined Charging Standard ("CCS") was previously authorized as a requirement.
>
> . . .
>
> (2) The allowance of Underwriter Laboratories ("UL") listed, or equivalent safety certification, splitter and dual-cord solutions as eligible costs toward the $500 rebate and $1,000 rebate for income qualified residential customers.

> . . .
>
> (3) The allowance of a residential referral credit for new enrollees.
>
> . . .
>
> (4) The ability for the customer to choose between receiving a rebate check or having the value applied as a bill credit.
>
> . . .
>
> (5) The addition of a rebate for public and fleet DCFCs that utilize battery arbitrage (i.e. charging the DCFC battery overnight to mitigate daytime, on-peak EV charging) to both minimize make ready service upgrades (given the significant supply chain challenges and demand for transformers) and optimize the load profile of the DCFC to 80% or greater off-peak. Again, this new rebate will be offered within the currently approved TEPs budget and does not include separate funding for make ready service like the pilot phases of the TEPs. The intent is to avoid significant make ready costs as the CIAC waiver does not apply at such host site projects.
>
> . . .
>
> (6) Finally, the Company proposes using any remaining make ready funds from the PowerMIFleet pilot to extend the income qualified enhanced rebate program for fleets.[142]

**Q. Are you concerned with these proposals?**

A. I am not concerned with the first four proposals (1 – 4) or the final proposal (6) and find them to be reasonable enhancements to the Company's EV programs. As described in further detail below, I am concerned with certain aspects of the remaining proposal (5), especially given that the Company is not seeking additional funding for public charging infrastructure in this case.

[142] Myrom Direct, pp. 9-10.

**Q. How does the Company project public DCFC will expand?**

A. In 2016, there were seven EVs to each public charging port in the U.S. By 2023, given growth in EV adoption, there were more than 20 EVs per public charging port.[143, 144] To address this growth, according to recent studies, the number of public and workplace charging ports in the U.S. will need to grow by over 1000 percent - from 216,000 to 2.4 million - between 2020 and 2030.[145, 146] In keeping with these trends, according to witness Myrom,

> utilizing the ratio of one fast charger per every 85 EVs, and growth rates trending between 500 and 630 thousand EVs by 2030, the Company projects 849 to 1,026 new DCFC service requests of 1 MW or greater by 2028, and 1,521 to 1,854 DCFC service requests of 1 MW or greater by 2030.[147]

**Q. Do you agree with these estimates?**

A. Based on the assumptions provided, I do not doubt the Company's estimate regarding how many DCFC service requests it expects to receive. However, it is important to note that these projections are based on a ratio of 85 EVs per public DCFC port. The Company points to market data and suggests that this is an ideal fast-charger-to-EV ratio.[148] However,

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[143] Osaka, S., *The Washington Post*, "For each public charger, here's how many EVs are looking to plug in," May 2024, available at https://www.washingtonpost.com/climate-solutions/2024/05/20/charging-stations-lag-ev-sales/.

[144] International Energy Agency, "Trends in electric vehicle charging," available at https://www.iea.org/reports/global-ev-outlook-2024/trends-in-electric-vehicle-charging.

[145] Bauer, G., *et al*., The International Council of Clean Transportation, "Charging Up America: Assessing the Growing Need for U.S. Charging Infrastructure through 2030," July 2021, available at https://theicct.org/wp-content/uploads/2021/12/charging-up-america-jul2021.pdf.

[146] Kampshoff, P., *et al*., McKinsey and Company, "Building the electric-vehicle charging infrastructure America needs," April 2022, available at https://www.mckinsey.com/industries/public-sector/our-insights/building-the-electric-vehicle-charging-infrastructure-america-needs.

[147] Myrom Direct, p. 8.

[148] *Ibid.*

as noted above, other recent studies suggest that the ideal number of total public charging ports (i.e., including both DCFC and Level 2 ports) to ensure convenient public charging is much higher (e.g., achieving a ratio of 8 to 12 EVs per public charging port[149]). Even in California, which has much higher market penetration of EVs than in Michigan, the ratio is 20 EVs per public charging port.[150] As such, the Company may receive a higher number of service requests for public charging infrastructure than it anticipates to satisfy demand.

**Q. How does the Company plan to support the deployment on these public DCFC?**

A. According to witness Myrom in a discovery response in this case (Exhibit MEIU-3 (LSS-3)), with the spending already approved, the Company will have supported a total of 137 DCFC sites (with approximately 324 ports[151]) at a total cost of $15.25 million. These DCFC sites were eligible for $70,000 rebates from the Company to partially cover the costs of the EV charging infrastructure and make-ready costs. The Company anticipates that nearly all of the currently remaining, already approved funds (i.e., $10.63 million[152]) will be used in the completion of the final ongoing projects with 72 of these site hosts.[153]

[149] Lowery, L., "Interactive index show how each U.S. state measures up in EV charging," *Repairer Driven* News, September 12, 2023, available at https://www.repairerdrivennews.com/2023/09/12/interactive-index-show-how-each-u-s-state-measures-up-in-ev-charging/#:~:text=Eight%20to%2012%20EVs%20per,to%20analysis%20from%20SBD%20Automotive.

[150] *Ibid.*

[151] Exhibit MEIU-4 (LSS-4).

[152] Exhibit MEIU-3 (LSS-3).

[153] *Ibid*.

Moving forward, as described in (5) above, the Company plans to offer DCFC rebates of up to $40,000 (again, as part of the previously approved budget) only for projects that have integrated battery energy storage systems. According to witness Myrom in a discovery response in this case (Exhibit MEIU-5 (LSS-5)), the Company estimates that it could provide approximately 40 of these rebates per year starting in 2026, such that "160 battery-integrated DCFCs are possible in the near-term launch of the program" (i.e., 40 rebates per year from 2026 to 2029).

**Q. Do you believe that the proposed rebates are appropriately sized for battery-integrated DCFC?**

A. According to witness Myrom in a discovery response in this case (Exhibit MEIU-6 (LSS-6)), based on an assumed cost of $100 per kWh of storage, the Company estimates that the $40,000 rebate would cover the additional cost of a 400 kWh of battery storage and, subsequently, would eliminate make-ready costs. If this is true, assuming total project costs (for two ports) of approximately $250,000 starting in 2026, the Company assumes this rebate would eliminate make-ready costs ($50,000), resulting in a 20% reduction in total project costs, and total project costs (for two ports) of approximately $200,000 (Exhibit MEIU-7 (LSS-7)). This calculation relies on two key assumptions: 1) that a battery storage system will cost $100 per kWh of storage and (2) that the installation of a 400 kWh battery will eliminate the estimated $50,000 in make-ready costs for a two-port project. Although I am unable to directly assess the validity of these assumptions, according to my conversations with Michigan EIBC members who represent companies in the EV charging space, including those familiar with battery-integrated DCFC, a rebate of $40,000 might

be too small to cover the entire costs of the battery. As such, it is possible that, given a $40,000 rebate, a site host might install a smaller battery (and thereby not eliminate all make-ready costs) or might incur additional costs to install a 400 kWh battery.

Separately, it is clear that the Company does not intend these new rebates to cover any of the costs of the DCFC itself. According to a discovery response in this case (Exhibit MEIU-6 (LSS-6)), as described above, the Company estimates that a 150 kW, two port DCFC project will cost $250,000 starting in 2026. Given that make-ready costs are estimated to be $50,000, each DCFC port is expected to cost approximately $100,000. This is not an insignificant cost, especially while utilization rates for DCFC are still growing. Without any additional rebates, a site host may not be able to install a battery integrated DCFC, even if the costs of the battery are largely covered by the Company's proposed rebate. As discussed below, although National Electric Vehicle Infrastructure ("NEVI") funding will support some of these charging stations, that funding will not be sufficient to fill the gap and meet the need for public charging to ensure the predicted benefits to ratepayers.

**Q. Will the proposed rebates for battery-integrated DCFC motivate site hosts to install a battery-integrated DCFC?**

A. Each site host's situation will be unique, but in general, a site host's willingness to purchase and install a DCFC primarily depends on a few factors, including: (1) the projected payback period of the project, which is based on the estimated utilization of the charger; (2) their available capital, and (3) their ability to access one or more public funding programs. In my experience, typically, site hosts are not willing to tolerate payback periods longer than

five years and are often more interested in a three-year payback time, which can be achieved by high utilization rates in well trafficked areas, or if public funding covers approximately 40 to 50% of total project costs.[154]

**Q. What do you recommend the Company's battery-integrated DCFC rebate should be?**

A. I will suggest two calculation methods, which arrive at roughly the same rebate level.

(1) It is clear that the Company's current $70,000 rebate per port for public DCFC is supporting deployment of DCFC infrastructure. As such, it could be assumed that this rebate is set at a reasonable level. If we assume that for a given project, some portion of the current DCFC rebate is used to cover make-ready costs, we can calculate an appropriate DCFC charger rebate for battery-integrated DCFC (assuming that the Company is correct that there will be no make-ready costs for such projects). The Company reports (Exhibit MEIU-6 (LSS-6)) that total average project costs (i.e., two ports) for DCFC projects to date were roughly $237,000 (i.e., $118,500 per port) and, without make-ready costs, were $191,000 (i.e., $95,500 per port). Given this, the current $70,000 rebate per port represents 59% of the total project costs. Applying the same percentage to a battery-integrated DCFC (without make-ready costs) would

[154] *See Strategic Planning To Implement Publicly Available EV Charging Stations: A Guide For Businesses and Policymakers, Center for Climate and Energy Solutions*; National Association of State Energy Officials and U.S. DOE Clean Cities, 2015, finding that: "Private investment in public charging stations is typically not profitable under current market conditions, as the revenues earned from offering public charging services do not offset the costs of purchasing, installing, and operating the stations within a typically attractive payback period of five years." at p. vii. https://www.c2es.org/wp-content/uploads/2015/11/strategic-planning-implement-publicly-available-ev-charging-stations-guide-businesses.pdf.

suggest that, to encourage similar market uptake, a rebate of $59,000 should be provided.[155] This rebate would be in addition to the $40,000 rebate for the battery itself.

(2) As stated above, site hosts are generally able to adequately lower the payback time for DCFC if public funding covers approximately 40 to 50% of the total project costs. For a cost of $100,000 per port, this would equate to a rebate of between $40,000 and $50,000 (again, in addition to the $40,000 rebate for the battery itself).

Given that this rebate would be in addition to the rebate designed to cover the costs of the battery, it may be possible to provide a lower additional rebate and still support deployment of battery-integrated DCFC.

**Q. How many public DCFC does the Company estimate will be needed in the coming years?**

A. According to the Company's 2024 TEP,

> Utilizing a ratio of one fast charger per approximately 85 EVs, the Company projects 849 to 1,026 new DCFC service requests [of] 1 MW or greater by 2028, and 1,521 to 1,854 DCFC service requests of 1 MW or greater by 2030. These estimates may well prove conservative as the State of Michigan has a goal of 100,000 chargers by 2030 in support of the 2 million EV goal (which Consumers Energy equates to approximately 45,000 public L2 and 5,000 public DCFCs in our electric territory).[156]

[155] As described above, the Company estimates that a battery-integrated DCFC port without make-ready costs will cost approximately $100,000 starting in 2026. A rebate of 59% of these costs would be $59,000.

[156] Consumers Energy Company's Transportation Electrification Plan 2024. Case No. U-21538. p. 8.

As explained in a discovery response in this case (Exhibit MEIU-8 (LSS-8), the Company does not propose in this case to extend rebates to these public DCFCs except for the roughly 160 rebates for battery-integrated DCFC anticipated between 2026 and 2029.

**Q. Why does the Company propose to focus new future rebates only on battery-integrated DCFCs in this case?**

A. According to witness Myrom in a discovery response in this case (Exhibit MEIU-5 (LSS-5)),

> The rationale for why DCFC rebates are not presently proposed is the same that was shared in prior rate cases. The State of Michigan is in the midst of disbursing approximately $110M in Federal NEVI funds for fast charging sites approximately every 50 miles along major travel corridors. The Company intends to revisit market conditions once NEVI awards near completion to see if areas remain that lack fast charging infrastructure and if fast charging infrastructure is pacing with EV adoption. The Company remains open to public DCFC rebates in the future depending on market conditions or significant policy changes (e.g. presently unspent NEVI funds are cancelled by the Federal government). As for rebates for battery integration with DCFCs, fast charging is the one segment that presently does not have load management opportunities that would be acceptable to the EV customer experience without the use of energy storage and arbitrage. Furthermore, we anticipate that market demand for DCFCs will require a significant increase in make ready infrastructure like transformers, and fast charging is a rapidly growing load segment as was shown in the Company's TEP filing and public meetings (e.g. the potential for 1,500 fast charging sites of 1 MW or greater by 2030). Thus, battery integration is anticipated to help address load management and make ready constraints, especially in rural areas with intermittent traffic and less charging and distribution infrastructure. Consumers electric territory covers wide swaths of rural areas. In sum, the Company remains very open to optimizing fast charging infrastructure from an access and load perspective, and will continually revisit this in future rate cases, settlements, and TEP filings.

**Q. Do you agree that NEVI funding will be sufficient to address public fast charging needs in the Company's territory?**

A. I do not believe that NEVI funding will be sufficient to address the public fast charging needs. As detailed in a discovery response in this case (Exhibit MEIU-9 (LSS-9)),

> According to the Michigan Department of Transportation's (MDOT) website (see National Electric Vehicle Infrastructure Formula Program (michigan.gov)), 39 sites were selected in Round 1, Round 2 selections to fill 43 additional gaps are anticipated in January 2025, and additional rounds will occur after that through Fiscal Year 2026 as necessary. Each fast-charging NEVI site will have at least 4 x 150 kW ports, but it is possible that some will have more. These are not Company owned developments and thus we do not have exact details regarding the total number of ports. Nonetheless, by early 2025, MDOT's implementation of NEVI funds should reveal how more than half of the NEVI funds will be utilized. Moreover, we estimate that a minimum of 328 fast charging ports should be underway (39 sites from Round 1 plus 43 sites from Round 2 totals 82 sites, and 82 sites times a minimum of 4 ports per site is at least 328 ports).

Not only is this estimate of NEVI-supported DCFC ports (i.e., 328 ports from Round 1 and Round 2) far lower than the Company's estimate of the number of expected applications it will receive (i.e., 849 to 1,026 service requests by 2028), all of the NEVI-supported DCFC ports will not all be located in the Company's territory – rather, these will be spread across the entire state. Furthermore, NEVI funding will be used primarily to deploy charging ports along highways. Michigan may only use its funds to deploy charging in communities if the state has fully built out the necessary infrastructure along all of its designated Alternative Fuel Corridors ("AFCs"), which it has yet to do. It remains unclear when and if electrification of the AFCs will be completed and how much funding (if any) will be available for charging infrastructure in communities. It is clear that there is a need to build out charging ports not only along highway corridors, but also within communities in publicly accessible areas such as parking garages, office complexes, shopping centers,

malls, parks, and beaches, etc. Given a projection of 500,000 EVs in the Company's territory by 2030, and a projected need for 5,000 public DCFC ports,[157] it is clear that the NEVI funding will not be sufficient to support the necessary public DCFC infrastructure.

The Company seems to agree with this conclusion, stating in a discovery response in this case (Exhibit MEIU-10 (LSS-10)) that

> The Company expects that the fast-charging market will transition from needing supplemental funding such as NEVI, to sustainable development independent of grants and rebates. The Company does recognize that additional support may be necessary in the interim.

**Q. Are utilities in other states making similar decisions to pause public DCFC funding to await the results of the NEVI funding?**

A. Not to my knowledge. In fact, utilities have proposed, and public utility commissions have approved, much larger transportation electrification programs in other states in recent years. For example, New York State has an $885 million make-ready program approved for transportation electrification,[158] the Massachusetts Department of Public Utilities recently approved nearly $400 million in statewide transportation electrification investments,[159] and Commonwealth Edison ("ComEd") anticipates spending $231 million

[157] Exhibit MEIU-10 (LSS-10).

[158] Joint Utilities of New York, "EV Make-Ready Program," available at https://jointutilitiesofny.org/ev/make-ready.

[159] Commonwealth of Massachusetts, "DPU's electric vehicle charging resources," available at https://www.mass.gov/info-details/dpus-electric-vehicle-charging-resources.

from 2023 to 2025 on EV programs and other Illinois Commerce Commission-approved beneficial electrification measures.[160]

**Q. Do you support the use of battery-integrated DCFC as proposed by the Company?**

A. Given the recent supply-chain challenges and the common need to upgrade utility infrastructure to accommodate DCFCs, I appreciate the Company's innovative proposal to support battery-integrated DCFC. As such, in concept, I do not oppose this proposal.

However, by limiting its future DCFC rebates to only apply to battery-integrated DCFC of 150 kW output or greater, the Company is missing opportunities to provide more public fast charging options, including non-battery-integrated DCFC. While I commend the Company's proposal to incorporate battery-integrated charging solutions to meet public charging demand in the face of supply chain and grid constraints, I am concerned, especially given the clear need and benefits of public EV charging infrastructure, that by only providing rebates for battery-integrated DCFC, the Company risks significantly limiting deployment of public DCFCs, which, as described above, will reduce drivers' access to infrastructure and will likely slow EV adoption, thus reducing the total financial benefits provided to ratepayers via downward rate pressure. Optimizing EV load to create these financial benefits is dependent on ratepayers charging at home, but as detailed previously, many mainstream consumers do not yet have enough confidence to buy an EV unless they see robust publicly available infrastructure, especially DCFC.

[160] ComEd, "ComEd Beneficial Electrification Plan," Compliance Filing May 2023, available at https://icc.illinois.gov/downloads/public/edocket/589765.PDF.

**Q. What do you recommend with respect to the Company's public DCFC rebate program?**

A. While a public charging program designed to support battery-integrated DCFC installations is valuable, it should be complementary to, and not in place of, broad support for public DCFC and make-ready programs as seen in several other states including California,[161, 162] Connecticut,[163] Georgia,[164] Illinois,[165]

[161] California Public Utilities Commission, Docket No. A.14-04-014, "Decision Regarding Underlying Vehicle Grid Integration Application and Motion to Adopt Settlement Agreement," January 28, 2016, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K241/158241020.PDF.

[162] California Public Utilities Commission, Decision 22-11-040, "Decision on Transportation Electrification Policy and Investment," November 21, 2022, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M499/K005/499005805.PDF.

[163] Connecticut Public Utilities Regulatory Authority Final Decision, Docket No. 21-08-06, "Annual Review of the Electric Vehicle Charging Program – Year 1," December 15, 2021, available at https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/372233877774b222852587ac005e47c2/$FILE/210806-121521.pdf.

[164] Georgia Public Service Commission, Docket No. 44280, "Order Adopting Settlement Agreement as Modified," December 30, 2022, available at https://services.psc.ga.gov/api/v1/External/Public/Get/Document/DownloadFile/192550/74325.

[165] Illinois Commerce Commission Order, 22-0432/22-0442 (Cons.), "Petition for Approval of Beneficial Electrification Plan under the Electric Vehicle Act, 20 ILCS 627/45 and New EV Charging Delivery Classes under the Public Utilities Act, Article IX and Investigation into Commonwealth Edison Company Beneficial Electrification Plan Filing pursuant to 20 ILCS 627/45," March 23, 2023, available at https://www.icc.illinois.gov/docket/P2022-0442/documents/349478/files/610872.pdf.

Massachusetts,[166, 167, 168, 169] Minnesota,[170] Missouri,[171] New Mexico,[172] New York,[173] Pennsylvania,[174] Rhode Island,[175] and Virginia.[176]

[166] Massachusetts Department of Public Utilities, Docket 17-05, "Order Establishing Eversource's Revenue Requirement," November 30, 2017, available at https://www.mass.gov/files/documents/2018/01/26/17-05_Final_Order_Revenue_Requirement_11-30-17.pdf.

[167] Massachusetts Department of Public Utilities, Docket 21-90, "Order on Petition of NSTAR Electric Company d/b/a Eversource Energy for approval of its Phase II Electric Vehicle Infrastructure Program and Electric Vehicle Demand Charge Alternative Proposal," December 30, 2022, available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/16827694.

[168] Massachusetts Department of Public Utilities, Docket 17-13, "Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for Approval of its Electric Vehicle Market Development Program, and of its Electric Vehicle Market Development Program Provision, pursuant to G.L. c. 164, §§ 76, 94, and Acts of 2016, c. 448," September 10, 2018, available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9800474.

[169] Massachusetts Department of Public Utilities, Docket 21-91, "Order on Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval of its Phase III Electric Vehicle Market Development Program and Electric Vehicle Demand Charge Alternative Proposal," December 30, 2022, available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/16827695.

[170] Minnesota Public Utilities Commission, Docket 18-643, "Order Approving Pilots with Modifications, Authorizing Deferred Accounting, and Setting reporting Requirements," July 17, 2019, available at https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={D017016C-0000-CD10-8791-F2FF6B5C1546}&documentTitle=20197-154444-01.

[171] Missouri Public Service Commission, Docket 2018-0132, "Order Approving Second Stipulation and Agreement," February 6, 2019, available at https://www.efis.psc.mo.gov/Document/Display/760285.

[172] New Mexico Public Regulation Commission Final Order Adopting Recommended Decision, Case No. 20-00237-UT, "I/M/O Public Service Company of New Mexico's Application for Approval of its 2022-2023 Transportation Electrification Program," November 12, 2021.

[173] New York Public Service Commission, Case 18-E- 0138, "Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs," July 16, 2020, available at https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={6238DD07-3974-4C4E-9201-3E339E311916}.

[174] Pennsylvania Public Utilities Commission, Docket No. R-2018-3000124, "Opinion and Order," December 20, 2018, available at https://www.puc.pa.gov/pcdocs/1599276.docx.

[175] Rhode Island Public Utilities Commission, Docket No. 4780, "Re: the Narragansett Electric Company d/b/a National Grid Proposed Power Sector Transformation Vision and Implementation Plan," August 16, 2018, available at https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/4770-4780-NGrid-Compliance-Filing-Book-1---August-16%2C-2018.pdf.

[176] Virginia Division of Public Utility Regulation, Case No. PUR-2019-00154, "Final Order. Petition of Virginia Electric and Power Company for approval of a plan for electric distribution grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia, and for approval of an addition to the terms and conditions applicable to electric service," March 26, 2020, available at https://www.scc.virginia.gov/docketsearch/DOCS/4m1j01!.PDF.

As such, I recommend that the Commission approve the Company's proposal to add a rebate for battery-integrated DCFC while also requiring the Company to increase the rebate for battery-integrated DCFC and provide additional funding for public DCFC infrastructure without battery-integration.

**Q. How much funding do you believe that Consumers should provide for DCFC rebates and make-ready expenses?**

A. The Company expects 1,521 to 1,854 new DCFC service requests through 2029, which equates means to 304 to 370 service requests a year. If 40 of these requests were for battery-integrated DCFC, this would leave approximately 264 to 330 non-battery-integrated DCFC service requests per year.[177] Assuming each of these DCFC were provided with a $70,000 per port rebate, the Company could support all of these service requests with $18.5 to $21 million. Understanding that the Company does not propose to support all these service requests, it would be reasonable for the Company to at least expand the DCFC rebate program by $6 million, enabling support for approximately 30% of the DCFC service requests over the next year.

Separately, given that the Company predicts that the current proposed battery-integrated DCFC rebate will cost approximately $1.6 million, if that rebate were approximately doubled (as described above), the Company would need to increase the program by approximately $1.6 million.

[177] Exhibit MEIU-5 (LSS-5).

Given that the Company's BCA projects approximately $570 million in downward rate pressure and only proposes to spend approximately $130 million via its Transportation Electrification Plan on customer programs,[178] allocating an additional $7.6 million (in total) for an increased battery-integrated DCFC rebate and expansion of the existing non-battery-integrated DCFC rebate program is feasible without unduly undermining ratepayer benefits from downward rate pressure.

## III. LAND LEASE PAYMENT TARIFF RULE

**Q. What does the Company propose in terms of land lease payments?**

A. As Company witness Thomas P. Clark describes in his testimony, land rights for utility-scale solar, wind, and storage projects are acquired through purchase, lease, or easement.[179] In addition to third-party developers, the Company and its affiliates are also developers of utility-scale renewable projects. In this case, the Company proposes to provide a new option such that any customer (Full Service or Retail Open Access) would be able to receive compensation for land leases and easements in the form of an electric utility bill credit.[180] According to the proposed tariff sheet changes, such payments and their amount would be mutually agreed to by the customer leasing the land and the Company.[181]

[178] Exhibit A-153 (JAM-3).

[179] Direct Testimony of Thomas P. Clark on behalf of Consumers Energy Company ("Clark Direct"), Case No. U-21585, p. 56.

[180] *Id.*, p. 56.

[181] Exhibit A-16 (BAG-2).

**Q. Why does the Company propose this option?**

A. According to witness Clark,

> In discussions with the Michigan Department of Natural Resources, they expressed a desire to receive land lease or easement payments in the form of a bill credit.[182]

In a discovery response provided in this case (Exhibit MEIU-11 (LSS-11)), witness Clark clarified that this was because the Michigan Department of Natural Resources ("DNR" or the "department")

> requested the Company to pay potential future lease agreements with bill credits to ensure the lease payments are used to cover operating expenses.

**Q. Do you support this proposal?**

A. No. While I am very supportive of the appropriate siting of utility-scale renewable projects on state lands, I am concerned that this proposal would give the Company an unfair competitive advantage.

One of the MI Healthy Climate Plan's key strategies to decarbonize the electric grid is to "implement a plan to site solar on state-owned lands and properties as quickly as possible."[183] To support this plan, there are a variety of state lands owned by DNR that the department may wish to lease for utility-scale renewable energy development.[184] I am supportive of this effort to determine which state-owned lands may be appropriate to leasing for utility-scale

[182] Clark Direct, p. 56.

[183] Michigan Department of Environment, Great Lakes, and Energy, "MI Healthy Climate Plan," April 2022, available at https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Offices/OCE/MI-Healthy-Climate-Plan.pdf?rev=d13f4adc2b1d45909bd708cafccbfffa, p. 33.

[184] Michigan Department of Natural Resources, "Renewable energy," available at https://www.michigan.gov/dnr/managing-resources/climate-action/renewable-energy.

projects. However, it is critical to ensure that fair value is provided for the lease of these public lands.

**Q. How can DNR ensure that a fair value is provided for any leases?**

A. In my opinion, the best way to ensure that a fair value is provided for any leased land is to institute a fair, open, competitive process to determine the best value the market is willing to provide for those land leases. This could be done by issuing a Request for Proposal ("RFP") for both utilities and third parties who may wish to lease state-owned land to site utility-scale renewable energy projects. By allowing all interested parties to participate and evaluating the proposals based on transparent metrics, DNR (or any other entity) can determine, in a competitively fair manner, that it is receiving the highest value possible for that public land.

**Q. Why do you believe that the Company's proposal would give it an unfair advantage?**

A. According to the Company, DNR requested that, in the case that DNR managed state land is leased to the Company, future lease payments be provided to DNR in the form of utility bill credits. Although I am not a lawyer, as a fundamental issue, it would first be necessary to determine whether DNR (or any other state agency) can accept payments for land leases as utility bill credits. This is specifically important because any such arrangement would occur outside of the annual appropriations process.

Setting this issue aside, if DNR wishes to accept land lease payments as utility bill credits, the only entity who could provide such utility bill credits is the utility. In other words, if a third-party developer leased state land from DNR, that developer would have no mechanism

to compensate DNR with utility bill credits and instead would have to provide a standard monetary payment for the land leases. Given this, at a minimum, such an option would likely establish a preference by DNR (and potentially other state agencies) to lease land only to investor-owned utilities like Consumers Energy. Even if DNR conducted a competitive process, if the department valued receiving bill credits instead of direct lease payments, only the utility would be able to compete effectively in the competitive process. Taken to the extreme, this option could set up an exclusive agreement to lease state-owned land in the Company's territory only to the Company.

I am concerned that such an outcome, without a fair, competitive process, could result in an undervaluation of state land for the state and the public. In addition, I am concerned that if the Company is able to lease state land for below market value, it may enable the Company to outcompete third-party developers, decreasing competition and potentially increasing costs for ratepayers.

**Q. What do you recommend regarding this proposal?**

A. I recommend that the Commission reject Consumers' proposal to establish a tariff option to allow customers to take land lease payments as bill credits.

## IV. ADVANCED METERING INFRASTRUCTURE

**Q. Please summarize the Company's AMI-related investments in this case.**

A. The Company's AMI-related investments are detailed in the proposed capital expenditures outlined in the low-voltage distribution ("LVD") metering sub-program, as well as

proposed IT expenditures associated with the enterprise software package provided by the Company's current AMI vendor. The details of each can be found in the direct testimony provided by witnesses Michael Kelly,[185] David Lynd[186] and Shivaji Kandan.[187]

**Q. What do you recommend with respect to the Company's AMI-related investments?**

A. My testimony on this topic does not directly raise concerns with the proposed expenditures described by the witnesses. Rather, I wish to draw attention to the Company's future AMI replacement strategy[188] and propose a separate, on-the-record proceeding on this topic. It has become clear that the Company is planning for and evaluating future AMI procurement scenarios.[189] Given the history and complexity of AMI-related issues raised by both the Company and the Commission in this case and those previously filed,[190] the interdependence of this technology on other systems, and the foundational nature of AMI and its importance to improving reliability and meeting clean energy goals,[191] I believe

[185] Direct Testimony of Michael Kelly on behalf of Consumers Energy Company ("Kelly Direct"), Case No. U-21585.

[186] Direct Testimony of David Lynd on behalf of Consumers Energy Company ("Lynd Direct"), Case No. U-21585.

[187] Direct Testimony of Shivaji Kandan on behalf of Consumers Energy Company ("Kandan Direct"), Case No. U-21585.

[188] Consumers is proposing to replace over 1 million 4G meters to meters compatible with a 5G cellular network by 2032. See Consumers Energy Electric Distribution Infrastructure Investment Plan ("EDIIP") 2024-2028, Case No. U-20147, p. 96.

[189] See Exhibit MEIU-12 (LSS-12).

[190] Commission order in Case No. U-16191, dated November 4, 2010 ("MPSC Order No. U-16191"); Commission order in Case No. U-16794, dated June 7, 2012 ("MPSC Order No. U-16794"); Commission order in Case No. U-17990, dated February 28, 2017 ("MPSC Order No. U-17990); Commission order in Case No. U-21458, dated July 7, 2023.

[191] *See* Exhibit A-118 (MPK-26). Consumers Energy and Commission Staff met in 2024 to discuss future value-focused AMI metrics, specifically DER deployment and proposed outcomes such as "supporting automating data modeling and forecasting of grid impacts from distributed energy resources (DERs) and electric vehicles (EVs) to provide planning departments with visibility of present and future capacity constraints on the LVD system as DER and EV penetration [increase]."

greater scrutiny and transparency into how the Company is evaluating its future AMI investments is required. Additionally, the bifurcation of this subject and creation of a separate open docket would allow for greater industry and stakeholder collaboration at a time of rapid technological transformation in the smart meter space. This is increasingly important as the Company considers the deployment of new technologies that can enable a cleaner, safer, more reliable electric grid.

**Q. Briefly describe the procedural history of the Company's initial AMI-investments.**

A. The Company proposed a $106 million investment in AMI technology deployment as part of its Smart Grid Program in its January 2010 general electric rate case (Case No. U-16191).[192] The Company stated that

> The program's emphases in this time frame will be the assessment, development and evaluation of information systems and field equipment, including the piloting and testing of smart meters [in order to] provide customers the opportunity to participate in programs that will allow them to better manage their energy costs.[193]

The Company listed benefits such as reduced operating costs associated with meter readings and turn-offs, reduced field trips, reduced theft, and the ability to detect service interruptions along with expedited restoration times. In summary, the Company provided this vision of AMI technology investments:

> AMI can provide the platform for future smart grid capability, including energy losses detection and ultimately optimize the efficient utilization of grid assets and detect and correct certain grid disturbances. Consumers will implement AMI in a manner that provides a solid foundation for future

[192] Exhibit of Ronn J. Rasmussen on behalf of Consumers Energy Company, Exhibit A-49 (RJR-1), Case No. U-16191.

[193] *Ibid.*, p. 3.

> smart grid development while mitigating the potential for the technological obsolescence of key AMI components.[194]

In November 2010, the Commission authorized the Company to continue the AMI pilot investments but denied spending for full AMI deployment as proposed by the Company. The Commission agreed with testimony provided by Staff witness Robert G. Ozar, agreeing that it was premature and would put ratepayers at financial risk to approve full AMI deployment prior to completion of the initial pilot phase.[195] Instead, the Commission adopted 11 policy recommendations proposed by the Staff with respect to future Smart Grid and AMI investments, including the following:

> Commission approval of Smart Grid cost recovery of full deployment must be pre-conditioned upon: a) CE achieving all major pilot milestones; b) demonstration that a full business case, (i.e. detailed lifecycle cost/benefit analysis) supports full deployment; and c) the filing of a comprehensive plan for specific customer programs that ensure that customers can obtain savings to offset the cost of Smart Grid infrastructure for which recovery is being requested.[196]

The Commission concluded that any capital expenditures directly related to the AMI pilot would not be reflected in rates until the Company completed the pilot phase and provided the Commission with a final report that detailed all project milestones, whether achieved or not achieved, and any decisions regarding technology functionality.[197] The Commission stated that

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[194] *Ibid.*

[195] MPSC Order No. U-16191, pp. 14–16.

[196] *Ibid*., p. 17.

[197] The Commission also ordered that, as part of the Smart Grid Collaborative, the Commission Staff had to complete an investigation and submit a separate report to the Commission on utility/vendor practices concerning AMI and Smart Grid technology research, development, and testing. That report is titled "Vendor Relationships with Smart Grid Deployments," and was filed by Commission Staff on April 1, 2011.

> [this] report will facilitate the Commission's decision making process with respect to the appropriateness of requiring customers to bear the costs of moving out of the piloting phase into full deployment.[198]

**Q. Did the Company provide this AMI pilot report in its next rate case?**

A. Yes, the Company provided a summary of the AMI Phase 1 Pilot in its next rate case (Case No. U-16794). The report contained a summary of the milestones, decisions, and learnings from the pilot, including but not limited to: 1) business requirements documented in use case workshops, 2) business process design workshops, 3) smart meter testing and certification requirements documentation, 4) establishing lab testing environments, 5) vendor product and performance assessment, 6) pilot installations completed, 7) vendor evaluation, and 8) a summary of the business case costs and benefits.[199] The business case indicated a total net present value ("NPV") benefit of $38 million for a full AMI deployment, with the vast majority of benefits accruing from avoided meter reading costs, avoided generation and transmissions costs due to alternating current ("AC") load control and demand response, increased meter accuracy and theft detection, and AMI-induced energy conservation and efficiency.[200] In response, Staff witness Nicholas M. Evans expressed concerns that the business case stated overly-optimistic assumptions related to projected useful meter life, the lack of budgeting for contingency funds, and the assumed

[198] MPSC Order No. U-16191, p. 19.

[199] Exhibits of Maureen K. Trumble on behalf of Consumers Energy Company, Exhibit A-44 (MKT-2), Case No. U-16794.

[200] Exhibits of Maureen K. Trumble on behalf of Consumers Energy Company, Exhibit A-45 (MKT-3), Case No. U-16794.

level of energy conservation among residential customers.[201] Witness Evans noted that the Company informed Staff that the meter vendor provides a 20-year warranty, but that this warranty does not cover technical obsolescence.[202] Further, witness Evans expressed that a lack of a contingency allowance ignores "the reasonable chance that various other components and software may need to be replaced early due to premature failure or obsolescence," and "that new and updated software may be needed to support future applications . . ."[203]

The Administrative Law Judge ("ALJ") in the case noted that all parties expressed concerns regarding the business case methodology.[204] Despite these concerns, Staff recommended the Company move beyond the Phase 1 Pilot and into Phase 2 to begin full AMI deployment, albeit with some recommended conditions for a cost recovery cap and capital expenditure reductions. The Commission ultimately authorized a full AMI deployment and declined to adopt Staff's additional conditions, stating that:

> The Commission has the authority to review all projected costs for this category in each rate case where costs are presented for inclusion in rate base for reasonableness and prudence, and is already able to disallow projected costs that do not meet those standards. With respect to weighing costs against benefits, the Commission finds that this authority is sufficient to ensure that unjustified costs are not passed along to ratepayers, and declines to adopt the Staff's proposed cap at this time.[205]

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[201] Direct Testimony of Nicholas M. Evans on behalf of Michigan Public Service Commission Staff, Case No. U-16794, pp. 8-11.

[202] *Ibid.*, p. 8.

[203] *Ibid.*, p. 9.

[204] Proposal for Decision, Case No. U-16794, March 30, 2012, p. 81.

[205] MPSC Order No. U-16794, p. 31.

**Q. What did the Commission require in terms of reporting related to the initial AMI investment?**

A. In its February 2017 Order in the Company's general electric rate case (Case No. U-17990), the Commission directed the Company to submit annual updates describing its AMI business case as well as an annual Smart Grid Report demonstrating how the Company and its customers are realizing the projected benefits from the initial AMI investments.[206] The Commission found that "continuing to provide a business case for AMI will aid the Commission in overseeing this program's implementation going forward."[207]

Subsequently, the Company has requested several times that the Commission relieve it of the annual reporting requirement to update the AMI business case.[208] For example, the Company argued in its March 2017 general electric rate case (Case No. U-18322) that the completion of the AMI installation period warrants relief.[209] The Commission disagreed, stating that

> merely completing the installation of meters and system enhancements does not conclude the implementation phase…The ongoing benefits of the program have not been well-documented and therefore, the Commission finds it necessary for Consumers to continue to update its AMI business case for the foreseeable future.[210]

[206] MPSC Order No. U-17990, p. 43.

[207] *Ibid.*

[208] See, *e.g.*, Application of Consumers Energy Company in Case No. U-18322, Filing No. U-18322-0001; Application of Consumers Energy Company in Case No. U-20134, Filing No. U-20134-0006.

[209] Direct Testimony of Lincoln D. Warriner on behalf of Consumers Energy Company, Case No. 18322.

[210] Commission order in Case No. U-18322, dated March 29, 2018, p. 80.

**Q. What issues has the Company had related to AMI as detailed in general electric rate cases?**

A. The Company appears to have two, major revolving AMI issues: (1) periodic changes to its cellular network, necessitating the need to procure hundreds of thousands of new meters[211] and (2) the adherence to the requirement to file annual updates to the AMI business case as part of each general electric rate case.[212] Separately, a third notable, yet standalone, issue involves meter malfunctions related to contaminated batteries.

**Q. Please describe the first issue related to AMI replacements in more detail.**

A. On October 7, 2019, the Company requested a temporary waiver of electric meter testing requirements,[213] and sought approval for an alternative testing process related to the replacement of its 3G AMI electric meters (Case No. U-20639).[214] In this request, Consumers explained that telecommunications companies were transitioning away from 3G cellular technology and planned to phase-out support for the Company's 3G AMI meters by the end of 2022.[215] Consumers' electric AMI meters use a cellular communications network to accomplish their 2-way communication capabilities, so once

[211] See Commission order in Case No. U-20639, dated December 19, 2019; Commission order in Case No. U-20639, dated February 23, 2023; Consumers Energy 2024-2028 Electric Distribution Infrastructure Investment Plan ("EDIIP"), Case No. U-20147, Filing No. U-20147-0093, pp. 95-96.

[212] Commission order in Case No. U-21389, dated March 1, 2024, p. 298.

[213] Michigan Administrative Code, "Technical Standards for Electric Service (Electric Technical Standards)," R 460.360.

[214] Application of Consumers Energy Company Application in Case No. U-20639, Filing No. U-20639-0001.

[215] *Ibid.*

the 3G technology was no longer supported, the Company's 3G AMI meters would no longer be able to provide functions like remote meter reads, remote turn-on/turn-off capabilities, and access to detailed energy usage.[216] The Company indicated that a total of 680,000 meters were identified as needing either direct replacement or retrofitting to support 4G technology and would be replaced by August 2023.[217] As of September 2023, according to the Company's Electric Distribution Infrastructure Investment Plan ("EDIIP"), 782 3G meters remain on Consumers network.[218]

**Q. Has this issue become relevant again?**

A. Yes. According to the Company's EDIIP, Consumers is again preparing for the retirement of its current cellular communications network, this time from 4G to 5G.[219] The Company's current plan is to replace its 4G LTE meters with 4G CatM1 or 5G meters prior to 2032, which is when its cellular contract is set to expire.[220] This will affect approximately 1 million meters and is slated to cost $406 million over nine years.[221] The Company's EDIIP outlines an incremental procurement strategy, starting with 50,000 meters per year in 2024, then increasing to 175,000 per year in 2027 and through 2032.[222] It is important to note,

[216] *Ibid.*

[217] *Ibid.*

[218] Consumers Energy EDIIP, Case No. U-20147, pp. 95-96.

[219] *Ibid.*

[220] *Ibid.*

[221] *Ibid.*

[222] *Ibid.*

however, that according to witness testimony in this case, Consumers has decided to defer replacement of 4G LTE meters to a later date.[223]

**Q. Please describe the second issue related to the business case in more detail.**

A. Despite repeated requests from the Commission, the Company continues to fail to provide a sufficient business case to satisfy the Commission that its AMI investments are reasonable and, despite repeatedly being denied, continues to request relief from annual reporting requirements. For example, in the Company's most recent general electric rate case (Case No. U-21389), the ALJ observed that:

> the current NPV for advanced metering is negative $60 million, far less than the company's original project of a positive NPV of approximately $40 million. While clearly more needs to be done to realize benefits of AMI, meter costs, which are significant, need to be contained.[224]

The Commission agreed in its Order stating that:

> (1) the Commission has previously determined that simply finishing the installation of AMI meters does not mean that the program is complete and that ongoing oversight is necessary to ensure AMI benefits are achieved; (2) while the company claims that the AMI business case is duplicative of other reports that Consumers is required to file, Consumers does not specifically mention any report that provides the same information as the AMI business case; and (3) although Consumers states that there has not been a significant change in the NPV since the assessment in Case No. U-20963, this is clearly not true, because *the business case presented here did not include the additional almost half billion dollars in investment to replace failed meters and upgrade to 5G compatible equipment*[225] (emphasis added).

[223] Lynd Direct, p. 177.

[224] Proposal for Decision, Case No. U-21389, p. 75.

[225] Commission order in Case No. U-21389, dated March 1, 2024, p. 298.

The Commission also clarified that the purpose of its annual business case update is not necessarily to justify an investment from over a decade ago, but to ensure that the Company and its customers are realizing the benefits of AMI on an ongoing basis. Further, the Commission expressed an interest in understanding

> opportunities for efficiencies and cost savings; more awareness of the system and its capabilities, including how such increased awareness can contribute to improved reliability; and how to leverage the AMI infrastructure to unlock opportunities for DER deployment.[226]

**Q. Please describe the third issue related to meter malfunctions.**

A. From 2020 through 2024, the Company and Commission Staff received hundreds of complaints from customers who received consecutive estimated bills (instead of measured bills).[227] It was determined through the Commission's complaint process that estimated billing from 3G and 4G meters had occurred prior to the expiration of the Company's 3G network.[228] In fact, in many cases, the cause of its estimated meter reads was not related to Consumers' cellular network at all; rather, the meters themselves were defective.[229] During discussions with Commission Staff, the Company confirmed that it was made aware of a battery contamination issue affecting 3G and 4G meters as far back as 2020, and that over

[226] *Ibid.*, p. 299.

[227] Commission Staff received 144 complaints in 2022 and an additional 33 complaints from January through May 1, 2024. Consumers reported 199 formal complaints and 111 informal complaints related to estimated electric meter readings since January 1, 2020. See Michigan Public Service Commission Staff, "Consumers Energy Company Meter Malfunctions, Estimated Billing Practices and Delays in New Service Staff Report," Case No. U-21458, Filing No. U-21458-0004 ("Staff Meter Malfunction Report"), p. 6.

[228] Staff Meter Malfunction Report, Case No. U-21458.

[229] Consumers Energy informed the Commission that these meters would test as accurate since the meters could accurately measure kilowatt hours, but the meters could not record or store the usage data. *See* Michigan Public Service Commission Staff, "Consumers Energy Company Meter Malfunctions, Estimated Billing Practices and Delays in New Service Staff Report," Case No. U-21458, p. 2.

900,000 meters could be potentially affected by this issue.[230] Moreover, the Company knew about this issue and failed to raise it when applying for a waiver extension of meter testing requirements in Case No. U-20639. In response to the complaints, the Commission initiated an investigation, which resulted in a settlement agreement, wherein the Company was found in violation of regulations and fined $1 million.[231]

This investigation exposes the overall need for more transparency and greater scrutiny. It also reveals the vulnerability of being locked into a single vendor when a crisis occurs. In a discovery response in this case (Exhibit MEIU-12 (LSS-12)), the Company described the limitations of this dynamic, stating:

> The present AMI technology deployed by the Company, including the collection engine, the system that interrogates the meters daily for billing determinants and meter events, is proprietary to a single vendor. The system and meters will not communicate with other vendor software, nor will the existing software communicate with other meter vendor products. That said, the Company is currently evaluating AMI technologies offered by both the present and other AMI vendors.

Furthermore, when describing the contributing factors that led to the high number of 3G meter failures, the Company discussed its inability to obtain sufficient quantities of replacement meters from its sole AMI vendor.[232] Consumers also stated that it "plans to be

[230] Staff Meter Malfunction Report, Case No. U-21458, p. 11.

[231] Commission order approving settlement agreement in Case No. U-21502, dated May 23, 2024.

[232] Staff Meter Malfunction Report, Case No. U-21458, p. 20.

more holistic in the future when it encounters multiple significant issues with a single vendor that may point to a larger more systemic problem."[233]

**Q. Given the Company's AMI history and recent issues, how is the Company planning for future AMI investments?**

A. This is not entirely clear to me. In this case, witness Lynd's testimony describes the Company's meter-related forecasting and total expenditures, which vary from year to year based on meter failures and 3G meter conversions.[234] Except for noting the Company's decision to defer its 4G LTE replacement strategy, direct testimony in this case does not discuss its future AMI investments, particularly as it relates to the Commission's stated interest in understanding how to leverage AMI infrastructure to unlock opportunities for DER deployment. It is also unclear how the value-focused AMI metrics that were identified during meetings between Commission Staff and the Company following the Commission's Order in the Company's last general electric rate case (Case No. U-21389),[235] will be fully considered in the context of the Company's broader technology investment strategy as proposed in its most recent EDIIP. The Company did provide insight into internal planning efforts on this topic in a discovery response in this case (Exhibit MEIU-12 (LSS-12)), stating that:

> Through the remainder of 2024, the Company is identifying and evaluating different scenarios for the future of its AMI technology, including but not limited to, maintaining the status quo, upgrading the existing vendor technology, switching to another vendor's products or utilizing multiple vendor products and systems. After this work is complete the Company will

[233] *Ibid.*, p. 10.

[234] Lynd Direct, p. 177.

[235] See Exhibit A-118 (MPK-26).

> benchmark the various options through the experiences of other utilities, vendors and industry groups, such as Edison Electric Institute (EEI).

In response to follow-up questions, in a discovery response in this case (Exhibit MEIU-13 (LSS-13)), the Company stated that:

> The Company identified scenarios in 2023 and the analysis of each scenario began in 2024. . . . The Company is looking at similar functionality in use today including automated reading and remote turn-on/turn-off, as well as new functionality being offered such as grid-edge computing. *The Company's business case, when developed, for future AMI technology will focus on technology obsolescence* (emphasis added).

When asked how stakeholders would be included and what venue(s) would be used to make these decisions, the Company responded that (Exhibit MEIU-13 (LSS-13)):

> The venue has not been decided yet as this work is still in the early stages. Previously, the Company has held technical conferences to engage with the Commission and stakeholders and it is possible that would be the forum for sharing this information. The Company's current evaluation of AMI technologies will not impact the AMI procurement decisions included in the time frame covered in this case.

**Q. Are you concerned with this proposed approach?**

A. Yes. I am concerned with the stated "technology obsolescence" business case referenced by the Company, especially given the rapid pace of change in advanced smart meter technologies, particularly in grid-edge computing. I also question how the Company is preparing to handle what Commission Staff noted in the Company's original AMI Phase I Pilot proceeding (in Case No. U-16794) twelve years ago – i.e., that technology obsolescence is not even covered by the AMI vendor's warranty.[236] Since that time, the Company has encountered situations, as described previously, where extenuating

[236] Direct Testimony of Nicholas M. Evans on behalf of Michigan Public Service Commission Staff, Case No. U-16794, p. 8.

circumstances have resulted in early obsolescence of technology thereby resulting in unplanned expenditures for which the Company has sought cost recovery.[237]

As referenced earlier in my testimony, the Company's 2024-2028 EDIIP states that it plans to proactively replace over 1 million 4G meters with 5G compatible meters by 2032 and that this purchase plan will cost $406.4 million over 9 years.[238] The EDIIP also states that the overall average lifespan of an electric meter is 20 years. If the Company does holistically evaluate its AMI challenges or widen its scope to require broader benefits from these assets, such as ensuring it can leverage AMI infrastructure to unlock opportunities for DER deployment, it significantly raises the chance of investing over $400 million in technology that cannot adapt to or support more distributed devices across its electric grid. Given the Company's history and noting the concerns raised above, I believe that the Company's planning and evaluation of next generation advanced metering should be held to greater Commission scrutiny, while allowing for broader stakeholder collaboration. This will result in a more comprehensive, and most importantly, transparent process.

**Q. How does the Company describe AMI as a supporting technology to meeting its stated reliability and clean energy goals?**

A. In witness Lynd's direct testimony, he states that "advanced metering is an essential component in many of the Company's present and future demand response and renewable

[237] *See* Lynd Direct, pp. 177–183 and Exhibit A-95 (MPK-3). Total expenditures in both LVD Metering subprograms have varied from year to year based on the quantity and mix of meters, metering transformers, and meter sockets the Company has had to purchase to meet the demand for failure replacements and to complete 3G meter conversions.

[238] Consumers Energy 2024-2028 EDIIP, Case No. U-20147, p. 96.

programs."[239] However, it is not clear how this technology is currently being used to enable these programs, nor is it clear how the Company intends to use advanced metering to support its future reliability goals and clean energy mandates. The Company's 2024-2028 EDIIP outlines its overarching five-year strategy to improve electric reliability, and while AMI is listed as a foundational technology, the details of its functionality are mostly described in the context of the nine-year replacement plan that is being driven by changes to the Company's cellular coverage.[240]

Separately, the 2024-2028 EDIIP identifies two major risks to Consumers' current and future distribution system: increasingly severe weather and technological innovation driving increased demand on the grid, primarily from DERs.[241] Preparing the electric grid for greater occurrences of extreme weather and the accelerated adoption of customer DERs is generally thought to be a central tenet of grid modernization planning.[242] An important component of this undertaking is a comprehensive evaluation of next generation AMI investments.[243] For example, public utility commissions in other states have initiated separate AMI investigations apart from, but corresponding to, broader electric distribution

[239] Lynd Direct, p. 177.

[240] Consumers Energy 2024-2028 EDIIP, p. 96.

[241] Consumers Energy 2024-2028 EDIIP, pp. 18–20.

[242] Department of Energy Office of Electricity, "A System In Transition: The Influence of Next Generation Technologies," May 2022, available at https://www.energy.gov/sites/default/files/2024-01/20-06-2022_doe-voe-a-system-in-transition-report.pdf.

[243] *Ibid.*

plans.[244] As demonstrated in each of these jurisdictions, utilities and regulators have rightly linked next-generation AMI investments to broader grid modernization plans that consider goals involving clean energy adoption, DER integration, reliability, and customer service.

**Q. What other states have initiated a state-wide examination of next generation AMI technology?**

A. Connecticut,[245] Colorado,[246] and Rhode Island[247] are leading examples of states that have initiated and/or completed state-wide examinations of next generation AMI technology. I will briefly describe each of these processes below.

[244] See, *e.g.*, Connecticut Public Utilities Regulatory Authority, "Investigation Into Distribution System Planning of the Electric Distribution Companies - Advanced Metering Infrastructure," Final Decision, Docket No. 17-12-03RE02, available at https://www.dpuc.state.ct.us/2nddockcurr.nsf/8e6fc37a54110e3e852576190052b64d/4e2d687f29bed43c85258a99005b3232/$FILE/171203RE02-010324.pdf; Public Utilities Commission of the State of Colorado, "In the matter of the application of Public Service Company of Colorado for approval to amend the certificate of public convenience and necessity for its advanced grid intelligence and security (AGIS) initiative," Decision No. R22-0131, Case No. 21A-0279E1, available at https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=967593; Joint Pre-filed Supplement Direct Testimony of Philip Walnock and Stephanie A. Briggs on behalf of Narragansett Electric Co. d/b/a Rhode Island Energy, "Advanced Metering Functionality ('AMF') Business Case," Docket No. 22-49-EL, available at https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2023-06/2023-06-05%20AMF%20Walnock_Briggs%20Supplemental%20Testimony%20%28Final%29_0.pdf.

[245] Connecticut Public Utilities Regulatory Authority, "Investigation Into Distribution System Planning of the Electric Distribution Companies - Advanced Metering Infrastructure," Final Decision, Docket No. 17-12-03RE02, available at https://www.dpuc.state.ct.us/2nddockcurr.nsf/8e6fc37a54110e3e852576190052b64d/4e2d687f29bed43c85258a99005b3232/$FILE/171203RE02-010324.pdf.

[246] Public Utilities Commission of the State of Colorado, "In the matter of the application of Public Service Company of Colorado for approval to amend the certificate of public convenience and necessity for its advanced grid intelligence and security (AGIS) initiative," Decision No. R22-0131, Proceeding No. 21A-0279E1, dated March 7, 2022, available at https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=967593.

[247] Joint Pre-filed Supplement Direct Testimony of Philip Walnock and Stephanie A. Briggs on behalf of Narragansett Electric Co. d/b/a Rhode Island Energy, "Advanced Metering Functionality ('AMF') Business Case," Docket No. 22-49-EL, available at https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2023-06/2023-06-05%20AMF%20Walnock_Briggs%20Supplemental%20Testimony%20%28Final%29_0.pdf.

*Connecticut*

In 2019, Connecticut's Public Utilities Regulatory Authority ("PURA") outlined four key objectives to modernize the state's electric grid, including AMI deployments for utilities Eversource Energy and United Illuminating Company. PURA issued a final decision that authorized and encouraged a statewide AMI deployment but did not pre-approve costs associated with the utilities' AMI plans.[248] Instead, PURA initiated a new proceeding to determine cost recovery and directed the utilities to submit new final AMI plans that included (1) an AMI Business Case, (2) AMI Competitive Solicitations, and (3) Customer Outreach and Engagement plans.[249] Within the competitive solicitation, PURA required the utilities to

> enable broad competition by allowing vendors to apply for separate components of the meter solicitation…including meters, communications network solution, meter data management system, customer information system, and outage management system integration,[250]

while also ensuring that "on-meter software can be upgraded without significant cost or that any upgrade costs required over the life of the meter are included in the proposal."[251] PURA also stated that effective AMI solicitations would consider companion grid modernization proceedings and that the Connecticut utilities should evaluate programs involving technologies like energy storage, EV charging, DER interconnection, non-wires

[248] Connecticut Public Utilities Regulatory Authority, "Investigation Into Distribution System Planning of the Electric Distribution Companies - Advanced Metering Infrastructure," Final Decision, Docket No. 17-12-03RE02.

[249] *Ibid.,* p. 7.

[250] *Ibid.,* p. 27.

[251] *Ibid.*

solutions, and reliability and resiliency frameworks by including said programs or frameworks as potential use cases in an AMI solicitation.[252]

*Colorado*

In 2017, the Colorado Public Utilities Commission ("COPUC") approved AMI investments proposed by the Public Service Company of Colorado in the Advanced Grid Initiative and Security ("AGIS") proceeding (Proceeding No. 16A-0588E). Utility testimony described AGIS as

> a long-term strategic initiative that is transforming the Company's electric distribution operations by enhancing security, efficiency, and reliability, enabling Public Service to safely integrate more distributed energy resources ("DERs"), and improving customer products and services.[253]

In December 2020, trade group Mission:Data filed a motion to reopen the proceeding so COPUC could consider next-generation metering functionality–also referred to as advanced grid edge computing–that the Public Service Company of Colorado had been deploying on AMI meters despite not receiving pre-approval from COPUC.[254] While COPUC denied the motion to reopen the entire proceeding, it found that the concerns raised by Mission:Data warranted further investigation to understand how advanced functionality

[252] *Ibid.*, pp. 28-29.

[253] Direct Testimony of Brooke A. Trammell on behalf of Public Service Company of Colorado, Case No. 21A-0279E, p. 19, available at https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=948367&p_session_id=.

[254] Public Utilities Commission of the State of Colorado, "In the matter of the application of Public Service Company of Colorado for approval to amend the certificate of public convenience and necessity for distribution grid enhancements, including advanced metering and integrated volt-var optimization infrastructure," Commission Decision Denying Motion and Ordering a New Application, Decision No. C21-0177, Proceeding No. 16A-0588E, p. 1, available at https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=942392.

would benefit utilities and their customers. Thus, COPUC adopted a Staff recommendation to open a new proceeding in which the Public Service Company of Colorado had to file an application that described, among other elements, the capabilities and value proposition for next-generation meters.[255]

*Rhode Island*

Also in 2017, the Narragansett Electric Company (d/b/a National Grid) filed with the Rhode Island Public Utilities Commission ("RIPUC") a proposed Power Sector Transformation Vision and Implementation Plan ("PST"). RIPUC docketed the PST filing in a standalone proceeding.[256] In the PST, National Grid proposed deploying advanced meters alongside implementing a vision to enhance distribution system planning and pursue beneficial electrification. In 2018, National Grid filed a Settlement Agreement that resolved all issues disputed by the parties in the PST filing.[257] The settlement included funding for grid modernization investments and the development of an updated Advanced Metering Functionality ("AMF") Business Case and contemplated the merits of filing a Grid Modernization Plan in addition to the AMF Business Case. RIPUC found an AMF Business Case to be integral to any Grid Modernization Plan, thus RIPUC encouraged

[255] *Ibid.*, p. 17.

[256] State of Rhode Island and Providence Plantations Public Utilities Commission, "In Re: The Narrangansett Electric Company d/b/a National Grid - Electric and Gas Distribution and Rate Filing," and "In Re: The Narrangansett Electric Company d/b/a National Grid - Proposed Power Sector Transformation Vision and Implementation Plan," Report and Order, Order No. 23823, Case No. 4770-4780, p.2, available at https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/4770-4780-NGrid-Ord23823-%285-5-20%29.pdf.

[257] *Ibid.*, p. 7.

National Grid to file both plans as close together in time as possible.[258] RIPUC also established sixteen elements that should be included in an AMF Business Case.[259] RIPUC approved the settlement in 2020, and National Grid (then operating as Rhode Island Energy) subsequently initiated a docket by filing its AMF Business Case.[260]

**Q. Why should the Commission open a separate docket to investigate Consumers next-generation AMI investments?**

A. When examining the Company's future plans in the context of with the original AMI procurement and procedural history, it is clear that stakeholders would benefit from a standalone docket to investigate the Company's current AMI replacement strategy. Specifically, it is clear that the Company's original AMI investment has yet to yield the benefits described in the original business case. As recently as the Company's last general electric rate case (Case No. U-21389), Commission Staff stated their position that

> the Commission should require Consumers to continue filing updates to its AMI business case until either 'the cumulative benefits exceed the cumulative costs or until the business case period has ended,' with the company's business case including all costs necessary to support benefits included within.[261]

[258] *Ibid*., pp. 22-23.

[259] *Ibid.*, p. 23.

[260] Joint Pre-filed Supplement Direct Testimony of Philip Walnock and Stephanie A. Briggs on behalf of Narrangansett Electric Company d/b/a Rhode Island Company, "Advanced Metering Functionality ('AMF') Business Case," Docket No. 22-49-EL, available at https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2023-06/2023-06-05%20AMF%20Walnock_Briggs%20Supplemental%20Testimony%20%28Final%29_0.pdf.

[261] Commission order in Case No. U-21389, dated March 1, 2024, p. 299.

The Company's failure to achieve the benefits stated in its AMI business case raises concerns in the context of the Company's prior requests for AMI meter testing waivers and subsequent meter failures leading to customer complaints. As referenced above, decreased oversight in the realm of AMI has led to increased costs and lower quality of service for ratepayers as AMI meters became stranded assets. Further, the Company's discovery responses in this case indicate that, while it is considering new functionality like grid-edge computing, it will continue to focus on technology obsolescence in developing a business case for future AMI deployment and will consider similar AMI functionality in use today. This narrow lens on next generation AMI risks underweighting the importance of new, meter-based functionalities that can facilitate DER adoption and integration, decarbonization, and grid resiliency, among other beneficial outcomes.[262]

With a narrow next-generation AMI business case and history of AMI implementation shortcomings, the Company risks another investment in stranded assets that will fail to maximize benefits for its customers. As the Company considers next-generation AMI investments as part of its strategy to replace meters that will be incompatible with the Company's future communications network, the Commission has an opportunity to open a standalone proceeding to investigate the Company's procurement process. A standalone proceeding focusing on how the Company plans to 1) evaluate desired next-generation AMI functionality and vendor capabilities, 2) develop a robust and comprehensive business case, and 3) execute a procurement and implementation strategy would better ensure that

[262] Deloitte, "Enabling the clean energy transition with next-gen advanced metering infrastructure," available at https://www2.deloitte.com/us/en/pages/energy-and-resources/articles/next-gen-advanced-metering-infrastructure.htm.

this investment fully maximizes potential benefits. Further, a separate proceeding on next-generation AMI would be an appropriate venue for the Commission and the Company to continue to define value-focused AMI metrics for future procurements with input from interested stakeholders.

**Q. Should the Commission consider broadening this next-generation AMI investigation to include other utilities?**

A. Yes. Consumers and DTE Electric Company are the two largest investor-owned electric utilities in Michigan that serve a combined total of approximately 4.1 million electric customers.[263] Both utilities have proposed major grid investments in their respective distribution system plans to improve reliability and prepare for the clean energy transition.[264] Additionally, both plans cite similar external forces including increased storm activity, electrification and distributed generation as drivers that are re-shaping the distribution grid.[265]

While there are similarities to both plans, as it relates to next-generation AMI, DTE Electric Company acknowledges that AMI systems are central to many of its ongoing and

[263] Consumers Energy, "Electric Business," available at https://www.cmsenergy.com/about-cms-energy/consumers-energy/default.aspx; DTE Energy, "About DTE," available at https://www.dteenergy.com/us/en/residential/about-dte/about-dte/about-dte.html.

[264] See Consumers 2024-2028 EDIIP and DTE Electric Company's 2023 Electric Distribution Grid Plan. Case No. U-20147, Filing No. U-20147-0095 ("DTE Grid Plan").

[265] *Ibid.*

upcoming capital investments, but notes "AMI was not initially developed and implemented to deliver reliability benefits,"[266] stating further that:

- DTE has reached the point where the future of AMI needs to be addressed to meet reliability needs. It is essential that the AMI system of the future meet several criteria:

- Capable of different types of architecture because the Company now requires a design that can deliver reliable, near-real-time sensing of power status down to the meter level rather than simple historical meter usage information after the fact. Power status information would also require the ability to detect open neutrals.

- More resilient and fault tolerant so the AMI system can be used for operations in addition to using it for static billing, which was the original design basis.

- More flexible in its capabilities to allow for the use of different tariffs, and more specific time of day rates for various uses of energy.

- *Capable of supporting new use cases including DERs, which requires more complex metering configurations to accurately separate generation, storage, and load and provide near-real-time reads to inform the ADMS tools of important electrical grid variations due to EV charging, vehicle to grid support, energy shifting with storage, weather-dependent generation and active control schemes used by customers and third-party aggregators.* New advanced meters may be able to provide control and submetering of separate connections at the same meter box which would greatly improve the management of DERs, EV charging, and demand response of large residential loads[267] (emphasis added).

DTE Electric Company's identification of the limitations of existing metering infrastructure is notably different from the description offered by Consumers. This discrepancy raises concern and warrants further statewide investigations to ensure that future AMI investments are reflective of the current and future challenges facing each

[266] DTE Grid Plan, p. 143.

[267] *Ibid.*

utility's distribution grid, and that customers are equally benefiting from these expenditures.

**Q. What do you recommend with respect to the Company's AMI investments?**

A. I recommend that the Commission open a separate proceeding to investigate the Company's future AMI procurement process. Given the Company's procedural history of AMI and other meter-related issues described above, I believe a standalone docket would allow for the robust evaluation of how the Company plans to 1) evaluate desired next-generation AMI functionality and vendor capabilities, 2) develop a robust and comprehensive business case, and 3) execute a procurement and implementation strategy to ensure that this investment fully maximizes potential benefits. Moreover, a separate proceeding on next-generation AMI would be an appropriate venue for the Commission and the Company to continue coordination to define value-focused AMI metrics for future procurements. I also recommend that the Commission consider broadening this proceeding to include other electric utilities. Since next generation AMI investments are currently under consideration at multiple utilities, there might be opportunities for greater collaboration and standardization across the state.

## V. CONCLUSIONS AND RECOMMENDATIONS

**Q. Please summarize your conclusions and recommendations to the Commission.**

A. I recommend that the Commission:

- Require the Company in future TEP BCAs to account for societal benefits such as reduced greenhouse gas emissions, reduced criteria pollutant emissions, reduced

noise pollution, reduced transportation fuel costs, improved physical and mental health, job creation, and economic impacts;

- Conduct a study to either establish a process by which each utility can quantify the societal benefits of transportation electrification in a standard manner or determine an estimated overall societal benefit per EV or per kWh of charging;
- Approve the Company's proposal to add a rebate for battery-integrated DCFC;
- Encourage the Company to provide an additional rebate for battery-integrated DCFC to cover some of the costs of the DCFC infrastructure (e.g., $40,000 to $50,000 per rebate) and approve approximately $1.6 million in additional funding for these rebates;
- Encourage the Company to expand the existing DCFC rebate program including by approving approximately $6 million in additional funding for public DCFC infrastructure *without* battery-integration;
- Reject Consumers' proposal to establish a tariff option to allow customers to take land lease payments as bill credits; and
- Open a separate proceeding to investigate the Company's (and other utility's) future next-generation AMI procurement process to 1) evaluate desired next-generation AMI functionality and vendor capabilities, 2) develop a robust and comprehensive business case, and 3) execute a procurement and implementation strategy to ensure that this investment fully maximizes potential benefits.

**Q. Does that complete your testimony?**

A. Yes.

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**STATE OF MICHIGAN**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

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|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for<br>the generation and distribution of<br>electricity and for other relief. | )<br>)<br>)<br>)<br>)<br>) | **Case No. U-21585** |

# DIRECT TESTIMONY OF JOHN D. ALBERS

**ON BEHALF OF**

**THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL,**

**INSTITUTE FOR ENERGY INNOVATION,**

**AND**

**ADVANCED ENERGY UNITED**

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## I. INTRODUCTION

**Q. Please state your name and business address.**

A. My name is John D. Albers. My business address is 1801 Pennsylvania Avenue NW, Suite 410 Washington, DC 20006.

**Q. By whom are you employed and in what capacity?**

A. Since October of 2023, I have been employed by Advanced Energy United, Inc. ("United") as the Director overseeing regulatory policy for central states where United is active. This includes Illinois, Michigan, Indiana, and Wisconsin.

**Q. On whose behalf are you testifying?**

A. I am testifying on behalf of the Michigan Energy Innovation Business Council, the Institute for Energy Innovation, and United, collectively referred to as "MEIU."

**Q. Did you prepare or direct the preparation of this testimony?**

A. Yes.

**Q. Please describe your background.**

A. I earned a Bachelor of Arts in Political Science from Illinois State University in 1994 and Juris Doctorate from the University of Illinois College of Law in 1997. I have been admitted to practice law in the State of Illinois since 1997.

In February of 1998 I joined the Illinois Commerce Commission ("ICC") as an Administrative Law Judge and presided over nearly every type of public utility matter that came before the ICC until I left in 2015. Issues I gained experience with include, but are not limited to, rate design, cost recovery, interconnection, metering, energy procurement, renewable energy credit procurement, and distributed generation. Over the years, I took on increasing responsibility, including overseeing informal agency workshops, testifying on behalf of the agency in legislative hearings, and recommending agency positions on proposed legislation.

After leaving the ICC, I practiced law until early 2022, representing and advising individuals, small and large businesses, small utilities, and state and national not-for-profit organizations on various matters pertaining to renewable energy, infrastructure siting, utilities, distributed generation, tariffs, and other issues. I frequently represented clients in matters before the ICC. During this period, I also worked part-time as a contract real estate developer for IPS Solar securing leases and permits for community solar projects in Illinois.

From March of 2022 until August of 2023, I oversaw SunPower Corporation's policy and strategy efforts in the Midwest. Until recently, SunPower was a national seller of residential rooftop solar energy systems. In this role I educated state utility regulatory commissioners and legislators and advocated for policies that would improve and expand the market for residential solar installations.

In my role at United, I advocate for policies at state utility regulatory commissions that enable greater deployment of advanced energy technologies with the ultimate goal of powering our economy with clean energy. This requires understanding member interests and priorities. Recent areas of interest include siting larger distributed energy resources ("DERs"), interconnection of both large and small DERs, as well as electric vehicle ("EV") charging stations, aggregation of DERs as part of virtual power plants ("VPP"), decarbonization of the natural gas distribution system, and better planning and coordination by and between electric and gas utilities. My work experience and education are set forth in detail in my resume, attached as Exhibit MEIU-14 (JDA-1).

**Q. Are you representing United as legal counsel as well?**

A. No. I am not representing United as legal counsel and am not testifying as an attorney. United will present its legal arguments in its briefs.

**Q. Have you previously testified before the Michigan Public Service Commission ("Commission")?**

A. No.

**Q. Have you previously testified before other state public utility commissions?**

A. Yes. I offered testimony in 2022 on behalf of the Joint Solar Parties in ICC Docket No. 22-0036 regarding net metering. I recently testified on behalf of United in ICC Docket No. 22-0486 pertaining to data access, a proposed spare transformer program, and DER management systems ("DERMS"). At the Indiana Utility Regulatory Commission, I

offered testimony on behalf of United in an investigation (Cause No. 46043) concerning whether DER aggregators are public utilities under Indiana law.

**Q. Are you offering any exhibits with your testimony?**

A. Yes, I am offering the following exhibits:

- Exhibit MEIU-14 (JDA-1): Résumé of John Albers
- Exhibit MEIU-15 (JDA-2): Discovery Response U-21585-MEIU-CE-0083
- Exhibit MEIU-16 (JDA-3): Discovery Response U-21585-MEIU-CE-0371
- Exhibit MEIU-17 (JDA-4): Discovery Response U-21585-MEIU-CE-0568
- Exhibit MIEU-18 (JDA-5): Discovery Response U-21585-MEIU-CE-0375
- Exhibit MEIU-19 (JDA-6): Discovery Response U-21585-MEIU-CE-0082
- Exhibit MIEU-20 (JDA-7): Discovery Response U-21585-MEIU-CE-0374
- Exhibit MEIU-21 (JDA-8): Discovery Response U-21585-MEIU-CE-0084

**Q. What is the purpose of your direct testimony in this proceeding?**

A. The purpose of my testimony is to respond to Consumers Energy Company's ("Consumers" or the "Company") proposed DER Optimization initiative and, separately, to recommend that the Commission direct the Company to prepare a proposal for maintaining an inventory of standard hardware with long acquisition lead times.

## II. DISTRIBUTED ENERGY RESOURCE MANAGEMENT

**Q. What does the Company propose regarding the management of DER?**

A. According to Consumers witness Scott A. McPhail II, DER management will be handled through its proposed DER Optimization initiative in two parts. First, the Company "will be

conducting industry benchmarking and learning sessions with key stakeholders to advance the development of a business case and optimal deployment strategy ..."[1] The Company will then take those lessons and findings and "will collaborate with an industry-leading consultant to formalize a business case and deployment strategy consisting of the implementation of a variety of hardware and software deployment projects ..."[2]

**Q. How does the Company define DERMS?**

A. The Company explains that a DERMS is "an enterprise scale software platform that is located at the utility's operational center."[3] This software monitors, controls, and optimizes DER "in a manner that maintains or improves the reliability, efficiency, and overall performance of the electric distribution system."[4] It "allows DER performance to be optimized for reliability and efficiency while simultaneously accounting for local, regional, and system-wide constraints and requirements."[5] Finally, the Company asserts that there is a need for "real-time grid information and control."[6] Specifically, "DER must be visible to and controllable by the Company's own employees to ensure reliable, affordable, and safe electric service."[7]

[1] Direct Testimony of Scott A. McPhail II on behalf of Consumers Energy Company ("McPhail II Direct"), Case No. U- 21585, p. 85.
[2] *Id.*, p. 85-86.
[3] Public Exhibits of Consumers Energy Company, Exhibit No.: A-111 (MPK-19), Case No. U- 21585, p. 36.
[4] *Id.*
[5] *Id.*
[6] *Id.*
[7] *Id.*, p. 138.

**Q. Is the Company's definition of DERMS accurate and complete?**

A. No. The Company's definition focuses exclusively on a centralized system within the utility's control center and the related functionality. Other industry stakeholders have defined DERMS much more broadly. For example, the Smart Electric Power Alliance ("SEPA") defines DERMS as "a control system specifically designed to handle DERs."[8] SEPA further characterizes DERMS as a "switchboard" for "DER-related protocols and information to simplify the management of" unrelated DERs and "feed information into other utility backend systems for planning, operations, and customer engagement."[9] SEPA's broader and more accurate description includes centralized DERMS, like those that fit under the Company's definition, as well as other types, such as "edge" DERMS and "fleet" DERMS, with their own applications and structure.

**Q. Can you describe what you mean by "edge" DERMS and "fleet" DERMS?**

A. Yes. As the name implies, "edge" DERMS refers to a DERMS that serves DERs at the edge of the grid, such as building or microgrid management systems.[10] "Fleet" DERMS refers to DERMS that serve a specific grouping of DERs independent of their location. This can include a fleet of EVs, a specific manufacturer's battery energy storage systems, or the DERs under the control of a single aggregator.[11] It is important to recognize that DERMS can be a valuable tool to not only manage DERs but also facilitate and advance state policies regarding the adoption of DERs and unlocking their potential to benefit the

[8] Ealey, B., "DERMS Terms – Going Beyond the Buzzword," Smart Electric Power Alliance, March 25, 2021, available from https://sepapower.org/knowledge/derms-terms-going-beyond-the-buzzword/
[9] *Id.*
[10] *Id.*
[11] *Id.*

grid and ratepayers. Therefore, the Commission should be mindful of how the Company intends to implement DERMS. Consumers' focus on a centralized DERMS is too narrow and precludes opportunities that exist through interoperability among the forms of DERMS used in the competitive marketplace.

**Q. Is this the first time the Company has proposed a DERMS?**

A. No, Consumers has proposed implementing a DERMS in its four prior electric rate cases, Case Nos. U-20697, U-20963, U-21224, and U-21389. In her testimony on behalf of MEIU in Case No. U-21389, Dr. Laura Sherman discussed Consumers' first three proposals.[12]

**Q. What did the Company propose related to DERMS in its 2020 general rate case, Case No. U-20697?**

A. Consumers proposed rate recovery for a projected $1,184,000 for the development of a DERMS. In support of the proposal, Company witness Richard T. Blumenstock testified,

> The Company will deploy DERMS functionality to optimize and control a limited number of DERs and address potential local operational challenges associated with DER penetration at the circuit and/or substation level. This will allow the Company to initially learn by monitoring and controlling DERs on a small subset of circuits and/or substations to understand the unique challenges associated with managing DERs in front of the meter. As DERMS mature, the Company will follow small-scale DERMS deployment with an Enterprise DERMS solution integrated with ADMS.[13]

[12] Direct Testimony of Laura S. Sherman on behalf of Michigan Energy Innovation Business Council, the Institute for Energy Innovation, and Advanced Energy United ("Sherman Direct"), Case No. U-21389, p. 20-25.
[13] Direct Testimony of Richard T. Blumenstock on behalf of Consumers Energy Company ("Blumenstock Direct"), Case No. U-20697, p. 153.

Mr. Blumenstock added that Consumers planned to first deploy a "small focused DERMS" on a small subset of circuits under a "first phase" from 2020 to 2022. This aspect of the proposal would cost approximately $3,000,000.[14]

**Q. What did the Commission conclude regarding Consumers' DERMS proposal in Case No. U-20697?**

A. The Commission's Order in Case No. U-20697 found that:

> For the reasons articulated in the [Proposal for Decision ("PFD")], the Commission adopts the findings and recommendations of the [Administrative Law Judge ("ALJ")]. The Commission agrees with the ALJ that Consumers' proposal lacked clarity, and the company failed to explain how reliability would benefit from the DERMS program or how the information that will be generated from the program will then be integrated into the reliability program. See, 8 Tr 3859-3863. Additional planning, including details on the sequencing of DERMS and other technologies to enhance system monitoring and controls and their integration with existing systems such as Consumers' outage management system, [Advanced Metering Infrastructure ("AMI")], and distribution supervisory control and data acquisition, is needed and prudent to pursue while DER penetration is still low. The Commission also notes that it may be valuable to further understand the evolving role and expectations of the distribution utility under the Federal Energy Regulatory Commission [("FERC")] Order 2222 when planning and designing new systems of this nature. The Commission encourages Consumers to include additional detail about how DERMS and other technologies will be sequenced and utilized to the benefit of its customers as part of its distribution investment and maintenance plan to be filed by September 30, 2021, including the opportunity for other stakeholders to comment on those plans as part of the draft plan shared by August 1, 2021. See, August 20, 2020 order in Case No. U-20147 (August 20 order).[15]

[14] Blumenstock Direct, Case No. U-20697, pp. 153–154.
[15] Commission Order in Case No. U-20697, December 17, 2020, p. 33.

**Q. What did Consumers propose related to DERMS in its 2021 general rate case, Case No. U-20963?**

A. In Case No. U-20963, Consumers proposed rate recovery for $1,191,000 for the development of a DERMS. The Company acknowledged that the Commission disallowed these costs in Case No. U-20697, but stated, "that the investments are still necessary because the company needs to learn more about monitoring and controlling DERs before DER penetration begins to increase."[16] The same Mr. Blumenstock testified,

> The Company will deploy DERMS functionality to optimize and control a limited number of DERs and address potential local operational challenges associated with DER penetration at the circuit and/or substation level. This will allow the Company to initially learn by monitoring and controlling DERs on a small subset of circuits and/or substations to understand the unique challenges associated with managing DERs in front of the meter. As DERMS mature, the Company will follow small-scale DERMS deployment with an Enterprise DERMS solution integrated with ADMS.[17]

This testimony was identical to the testimony submitted by Mr. Blumenstock in Case No. U-20697.

**Q. What did the Commission conclude regarding the Company's DERMS proposal in Case No. U-20963?**

A. In that case certain intervening parties, including the Attorney General, Clean Energy Organizations, Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan, contended that the proposed DERMS spending was unsupported and premature in light of the limited number of DERs on the

[16] Case No. U-20963, 5 Tr 785-788.
[17] Blumenstock Direct, Case No. U-20963, p. 160.

system and the statutory cap on distributed generation ("DG"). Considering these arguments, the Commission found that:

> Consumers' evidence in the instant case makes no attempt to address the issues articulated by the Commission in the December 17 order [in U-20697]. Consumers provided no substantiation for the prediction that DERs will increase more than 100-fold to 550 MW in 2022, made only very general statements in support of its request, and ignored the obvious barrier of the existing DG cap. The Commission can only reiterate its remarks from the December 17 order, and adopts the findings and recommendations of the ALJ. The Commission continues to seek the information addressed in the above quote from the December 17 order, page 33, and awaits a demonstration of how DERMS will provide an advantage to ratepayers by unlocking the benefits of DERs for customers. This is the type of evidentiary support that may result in approval of rate base treatment for this cost category in the future.[18]

**Q. What did Consumers propose related to DERMS in 2022 in Case No. U-21224?**

A. In that case, Consumers proposed to deploy a DERMS by the end of 2023. That deployment would start with the installation of, "up to five de-centralized DERMS controllers. … The distributed system is also connected to the cloud-based DERMS which manages the registration and scheduling of all the distributed sites and can perform aggregated functions."[19] The Company estimated that these installations would cost $1,200,000.[20] It also sought full recovery of the $1,168,389 spent on the Cadillac DERMS installation in 2021[21] despite the Commission disallowing recovery for the expenses associated with that project in the previous rate case (Case No. U-20963).[22]

[18] Commission Order in Case No. U-20963, December 22, 2021, p. 40.
[19] Direct Testimony of Mark A. Ortiz on behalf of Consumers Energy Company ("Ortiz Direct"), Case No. U-21224, p. 53.
[20] Ortiz Direct, Case No. U-21224, p. 53.
[21] Ortiz Direct, Case No. U-21224, p. 53-54.
[22] Ortiz Direct, Case No. U-21224, p. 53.

**Q. What was the outcome of that proposal in Case No. U-21224?**

A. The parties in Case No. U-21224 reached a unanimous settlement agreement.[23] Notably, the Company's proposed DERMS spending was not part of the settlement agreement and not approved for cost recovery.

**Q. What did the Company propose related to DERMS in its 2023 general rate case, Case No. U- 21389?**

A. On May 1, 2023, in Case No. U- 21389, the Company did not request rate recovery for any DERMS-related proposals. Instead, Consumers described a two-step DER Optimization initiative which involved (1) deployment of de-centralized DER Gateways and (2) integration of these DER gateways under a centralized DERMS. Consumers proposed implementing these initial DER Gateways in conjunction with other Company projects, including the "Cadillac Solar Gardens project, the 200 Building project, the Parkview Battery project, and the EV School Bus project."[24]

**Q. What did the Commission decide relative to these DERMS proposals in Case No. U-21389?**

A. Although the Commission approved no DERMS-related capital expenditures, in its March 1, 2024 Order it agreed with MEIU that the Company "should continue to engage with the Staff and interested persons on these DER-related topics."[25]

[23] Commission Order Approving Settlement Agreement in Case No. U-21224, January 19, 2023.
[24] Direct Testimony of Matthew S. Henry on behalf of Consumers Energy Company, Case No. U-21389, p. 55.
[25] Commission Order in Case No. U-21389, March 1, 2024, p. 43.

**Q. What do you conclude from the previous Commission decisions on DERMS in Case Nos. U-20697, U-20963, U-21124, and U-21389?**

A. Consistent with Dr. Sherman's testimony in Case No. U-21389 related to the first three of the four prior rate cases,[26] I understand the Commission to want to see a better explanation of how any DERMS investments will be utilized and benefit ratepayers before it will approve any implementation plan or rate recovery related to DERMS. Specifically, it appears that the Commission wants to see how a proposed DERMS investment would benefit reliability, be integrated into existing distribution automation systems, be sequenced with other technologies, and be utilized to benefit customers. The Commission also appears to expect Consumers to engage Staff and other interested stakeholders to learn about different DERMS options and the needs of stakeholders, including through Commission workshops.

But rather than follow the Commission's direction to provide the missing justification for DERMS, over the last four years the Company has simply trimmed around the edges and rebranded its DERMS proposal. For instance, and as noted above, despite the Commission's specific request for more information related to any future DERMS proposal, Company witness Blumenstock provided identical testimony in Case Nos. U-20697 and U-20963. Similarly, when the Commission again denied this spending in Case No. U-20963, in the next rate case (Case No. U-21124), Consumers submitted for recovery costs associated with the Cadillac DERMS installation despite that spending being denied in Case No. U-20963. Finally, since the Order in U-21389, Consumers has failed to

[26] Sherman Direct, Case No. U-21389, p. 24-25.

properly engage stakeholders. Disturbingly, as detailed in a discovery response in this case, Consumers considers attendance at the Commission's three DR/DER workshops under Case No. U-21297[27] and engagement with utility industry members sufficient engagement with stakeholders.[28] Notably, Consumers does not report initiating any DER or DERMS outreach of its own.[29]

**Q. How does Consumers describe its current DER Optimization proposal?**

A. Consumers is proposing a Company-owned and -operated[30] DERMS that,

> …lays the groundwork for standardized methodology to deliver important capabilities, including but not limited to modeling, monitoring, operating, and coordinating, needed for optimizing and safely integrating DER into the electric distribution system.[31]

According to Consumers, it will evaluate, plan, develop, and implement management of DER across the full spectrum of technologies (hardware and software) through the implementation of DERMS. This DERMS will purportedly be an enterprise-scale software that is located at the Company's operation center.[32] The results of this proposal, if successful, will be used for the management of increased DG, given Michigan's recently increased DG "soft cap" to 10% of each utility's 5-year average peak load.[33]

[27] Commission Staff has hosted three DR/DER workshops on January 23, February 22, and June 5, 2024. The agendas, presentations, and recordings of the meetings are available on the Commission's website at: https://www.michigan.gov/mpsc/commission/workgroups/demand-response-aggregation. Aspects of DERMS have been raised but have not been the sole focus of the meetings. Thus, the Company's claim that it has engaged stakeholders regarding DERMS at the workshops is questionable.
[28] Exhibit MEIU-15 (JDA-2).
[29] *Id.*
[30] Exhibit MEIU-16 (JDA-3).
[31] McPhail II Direct, Case No. U- 21585, p. 84-85.
[32] McPhail II Direct, Case No. U- 21585, p. 85.
[33] *Id.*, p. 86.

The project also includes DER gateways, which will be used to "optimize controllable resources based on local conditions, as well as provide communications and translation services to a diverse set of DER."[34] At first, these DER gateways will focus on the grid-edge and include solar arrays, batteries, EV chargers, and circuit-level deployments. Later, as DER penetration increases, the Company plans to deploy the system to provide "system-level grid benefits such as peak shaving and market participation."[35] It also plans to update its control center for DERMS-related needs.[36]

Consumers does not seek to recover any costs associated with its study and proposal period, but requests recovery of $6,633,000 in capital expenditures in the test year for the DER Optimization initiative.[37]

**Q. Are there any substantive differences between this DERMS proposal and the DERMS proposals in previous rate cases?**

A. The description offered by witness McPhail is very general, so any distinctions from earlier DERMS proposals are difficult to discern from his testimony. In response to a discovery request wherein MEIU asked Consumers to identify and describe what the Company believes to be the substantive differences between the pending DERMS proposal and the four earlier proposals, with specific attention to any differences the Company deems significant related to cost, ownership of DERMS assets, benefits to ratepayers, operation and control of DERs, proposal rollout schedule, and benchmarks for program evaluation, Consumers simply stated that the "primary difference ... is that Michigan's 2023 clean

[34] Public Exhibits of Consumers Energy Company, Exhibit No.: A-111 (MPK-19), Case No. U- 21585, p. 136.
[35] *Id.*, p. 137.
[36] Exhibit MEIU-17 (JDA-4).
[37] McPhail II Direct, Case No. U- 21585, p. 86.

energy law raised the statutory distributed generation cap from 1% of utility peak load to 10%."[38] The Company added that it will need to ensure it can manage greater DG penetration in the near term rather than waiting for DG penetration to near the 10% cap.[39] Based on this response, I understand Consumers to concede that its current DERMS proposal is substantively no different from its earlier proposals, but that only the circumstances of Michigan law have changed.

**Q. Does the statutory change in the DG "soft cap" warrant approval of Consumers' DERMS proposal in this rate case, the fifth case where it has been raised?**

A. No. Consumers' DER Optimization proposal still suffers from the same shortcomings previously referenced by the Commission when rejecting it: a lack of clarity, incomplete plans, insufficient details, a lack of stakeholder input, and a failure to demonstrate how DERMS will provide an advantage to ratepayers by unlocking the benefits of DERs for customers. Regarding stakeholder input, as noted above, the Company seems to be relying on the three workshops hosted by Commission Staff for stakeholder input. More ambiguous is its assertion in a discovery response in this case that it has engaged in "industry benchmarking and learning sessions" with other utilities and the Electric Power Research Institute, Utility Communications Architecture, Institute of Electrical and Electronics Engineers, and SEPA.[40] Given the Commission's explicit instructions regarding stakeholder engagement in Case No. U-21389, Consumers should commit to initiating workshops open to any interested stakeholder focused on DERMS development

[38] Exhibit MEIU-18 (JDA-5).
[39] McPhail II Direct, Case No. U- 21585, p. 86.
[40] Exhibit MEIU-15 (JDA-2).

before it proceeds with implementing its DER Optimization initiative and before the Commission approves any element of the initiative. Such workshops must be meaningful, and not merely a box-checking exercise. In other words, Consumers must commit to giving stakeholder input serious consideration and incorporate reasonable stakeholder recommendations. Any eventual DERMS proposal should not simply be the sixth iteration of what has already been proposed and rejected by the Commission.

**Q. Why is it important for the Company to accept input from a broader group of stakeholders?**

A. First, as I noted above, doing so is consistent with the Commission's last order addressing Consumers' DERMS proposal in Case No. U-21389. Specifically, in response to a recommendation by MEIU, the Commission directed Consumers to "continue to engage with the Staff and interested persons on these DER related topics."[41] The Company should rectify its *de minimis* effort regarding engagement with interested persons and work, at least, directly with those who requested the opportunity to provide input.

Second, assuming Consumers is interested in making the best of DERs for the benefit of the grid, ratepayers, and DER owners, it is logical and reasonable to expect the Company to engage DER aggregators, i.e., entities with significant experience operating DERs. Based on the information provided to date, however, it does not appear that Consumers has directly engaged aggregators. This lack of engagement is especially problematic when the Company seeks to spend millions of ratepayer dollars. Third, by communicating with DER

[41] Commission Order in Case No. U-21389, March 1, 2024, p. 43.

aggregators, Consumers is likely to learn a great deal about developing a DERMS that is interoperable with the various DERMS maintained by aggregators. This alone is reason enough to broadly engage with DER aggregators in light of FERC Order 2222, which instructs regional transmission organizations and independent system operators to allow DER aggregations to participate directly in the wholesale markets through DER aggregators.

**Q. Company witness McPhail suggested that the DER Optimization initiative would support FERC Order 2222. Does that warrant approval of Consumers' fifth request for approval of a DERMS?**

A. Mr. McPhail testifies that to ensure the success of FERC Order 2222, "it is critical that utilities have real-time operational visibility and coordination of these DERs participating in electric markets."[42] He opines that the "DER Optimization initiative will enable these market interactions…"[43] I generally agree that DERMS can be useful toward integrating and managing aggregated DERs, such as the aggregations contemplated under FERC Order 2222. But that does not mean that any DERMS proposal warrants approval. As with any system for managing diverse and dispersed assets, it must be designed well. A poorly conceived DERMS does not benefit the grid, ratepayers, or the DERs it is intended to coordinate. As described above, the Commission has previously questioned the value of Consumers' DERMS proposals and sought additional information, so it appears that the Commission also appreciates the value of a well-designed DERMS. The issuance of FERC

[42] McPhail II Direct, Case No. U- 21585, p. 85.
[43] Id.

Order 2222 does not overcome or negate the concerns surrounding the Company's DERMS plans.

**Q. What additional issues should the Company explore in the broader engagement efforts you recommend?**

A. It is important to consider the business case for establishing a DERMS and to what extent third parties can provide some of the functionality of a DERMS. Consumers asserts that its ownership and operation of a DERMS is critical to ensuring that the distribution system is operated in a "safe, reliable, stable, efficient, secure, and affordable manner." For this reason, "the Company does not consider third-party ownership or operation of DERMS to be an acceptable alternative."[44] Notably, there is nothing in the record to justify this assertion. In considering this issue, the Company would be wise to seek information from the competitive market regarding cost-effective technologies and solutions as part of its business case, including in, but not limited to, the workshops I recommend.

Although the utility will always have a critical role to play in signaling specific needs that DERs can respond to, there is no reason to assume that a utility-owned and operated centralized DERMS is the only means to achieve some or all of the desired capabilities and functionality. Depending on the use cases and available solutions, DER management can be achieved cost-effectively by third-party services, which perform similar functions to that of a centralized utility-owned enterprise DERMS and remain responsive to a utility control center. These third-party service providers are specialized companies offering

[44] Exhibit MEIU-16 (JDA-3).

expertise in managing DERs effectively based on the utility's strategic objectives. This approach can also provide avenues for interoperability between different DERs and third-party service providers. The Company could also discuss pilot projects with third-party service providers to perform proof of concepts and gain an enhanced understanding of the implementation of DER management solutions. Throughout these initial explorations, I recommend that the Company participate in industry benchmarking exercises to identify how peer utilities approach DER management challenges.[45]

**Q. Are there issues related to utility control that should be explored in the engagement efforts?**

A. Yes, utility control of individual DER assets is another area that warrants discussion. The Company states that "DER must be visible to and controllable by the Company's grid operators to ensure reliable, affordable, and safe electric service."[46] Exactly to what extent Consumers intends to "control" DER assets that it does not own is not reflected in the Company's testimony and how utility control "ensures reliable, affordable, and safe electric service" is not explained. I am concerned that if Consumers intends to exercise full control over DERs, at least two adverse results may occur. First, customers will be less likely to participate in aggregation programs if they perceive a loss of control over their asset, some types of which can be quite costly, such as solar arrays or battery storage systems. Presumably the Company does not intend to exert control over any new DER, such as a behind-the-meter battery, smart thermostat, or smart water heater, installed by a customer without that customer consenting and offering their new device as a DER for use

[45] Cf Sherman Direct, Case No. U-21389, p. 27-28.
[46] Public Exhibits of Consumers Energy Company, Exhibit No.: A-111 (MPK-19), Case No. U- 21585, p. 138.

to support the grid. But even assuming customer consent is a prerequisite, customers may be less likely to turn over control of their new asset, particularly more expensive assets, if it means an entity that made no investment in the asset will control and benefit from it. If customers are discouraged from allowing their DERs to be used for the benefit of the grid, one of the most valuable means of reducing load and reducing rates will be removed from the table. Second, utility exclusion of third-party participation deprives ratepayers of potential savings available through the competitive market. In light of these concerns, these issues should be covered in the recommended workshops.

Consumers could also learn a great deal from engaging DER aggregators, who have experience working with utility customers who own DERs and are sensitive to their use. Consumers should use the workshop opportunity to identify and outline virtual power plant ("VPP") programs utilizing DERs aggregated by third parties, including general compensation structures for use of customer-owned DERs. The Company acknowledges not having identified a compensation structure at this time,[47] but doing so may help support a case for benefits to customers from a DERMS.

Consumers should also be prepared to discuss whether its objectives are aligned with the needs of all grid stakeholders and the enablement of DER adoption. DERMS is a very ambitious technology that can enable a wide range of use cases and benefits across many different facets of the power system. These can range from distribution-focused functions intended to maintain reliability or improve efficiency to market functions like energy

[47] Exhibit MEIU-6 (JDA-6).

market participation, DR, and beyond. Developing a business case is also essential in making informed technological choices and ensuring that all reasonable alternatives have been evaluated. Where there may be other solutions that meet one or more of the identified needs or benefits, consideration of those solutions ensures the reasonableness and necessity of the Company's proposal. This way, this Commission can choose the most reliable, effective, and affordable option on behalf of the Company's ratepayers.

**Q. Assuming the Company follows your recommendation and returns to the Commission with a new DERMS proposal reflecting stakeholder input, what other information should Consumers provide to explain its proposal?**

A. Consistent with Dr. Sherman's proposal in Consumer's prior rate case,[48] the Company should provide a comprehensive DER forecasting study reflecting a time horizon spanning at least 20 years (at 5-year increments) to demonstrate a clear understanding of the anticipated uptake of electrification and penetration of DER. The forecast should also be broken down by technology type (e.g., solar plus storage, EVs, smart thermostats, etc.), since such information could be useful in determining and designing the initial phase(s) of DERMS implementation, including the vendor selection process since it will be easier to identify third-party vendors that have expertise in providing services related to certain DER types or DER management objectives. Logically, this research and assessment should be undertaken before Consumers implements a centralized enterprise DERMS platform because it may learn through the research and assessment that such an investment is not necessary to provide the desired benefits.

[48] Sherman Direct, Case No. U-21389, p. 29.

The Company should also demonstrate that it evaluated the opportunities and potential customer challenges related to using distribution-connected resources for market functions. This includes discussing the impact of DERMS on DER owners. For example, Consumers should address how DERMS may affect positively and/or negatively interconnection processing times, overall project timelines, and installation costs. To the extent that there are negative impacts, the Company should identify ways to negate or mitigate such impacts. Any such changes may also discourage third-party DER providers and aggregators from entering the Michigan DER marketplace.

The Commission should also direct Consumers to submit with any future DERMS proposal effective methods to notify and educate DER owners and third-party aggregators regarding changes related to DERMS. Clear communication strategies should be developed to educate DER owners and aggregators on how to maximize the benefits that a DERMS can provide. The diverse landscape of DERs can add a layer of complexity around configuration challenges and can create technical limitations. By preparing to address these issues, the Company can better demonstrate the depth of its consideration and position itself for successful implementation and long-term DER owner satisfaction.

A troubling aspect of the Company's current proposal is that it apparently already has a plan to spend $6,633,000 on hardware and software during the test year,[49] yet acknowledges that its benchmarking and learning sessions are ongoing[50] and that it is still

[49] Exhibit MEIU-17 (JDA-4).
[50] Exhibit MEIU-15 (JDA-2).

"exploring strategies to support DER optimization."[51] This is problematic because learning and planning should always precede deployment, especially when spending other people's (i.e., ratepayers') money. By demonstrating that it has fully considered the various aspects of DERMS deployment and developed a sound implementation strategy consistent with Michigan's decarbonization goals, Consumers can enable the Commission to make an informed decision regarding a future DERMS proposal. If and when that time comes, the Commission should ensure that the DERMS design can accommodate a competitive marketplace for DER providers and aggregators.

**Q. Earlier you referenced third parties providing DER management solutions. Can you provide any examples?**

A. My colleague, Dr. Sherman, addressed this issue in her testimony in the Company's most recent prior rate case, Case No. U-21389. [52] She points out several third parties who provide DER management solutions. She cites SolarEdge who "provides grid services and near-real-time aggregative control for monitoring and controlling DERs, including PV inverters, residential storage, and EVs, for the creation of a VPP."[53] Additionally, she notes that Stem optimizes DERs like battery storage to enhance the grid and DR.[54] These examples demonstrate that a third party who owns a DERMS platform can still work with and be aligned with a utility's control center. For this to happen, it is crucial that a utility's DERMS is interoperable with the systems employed by third parties and has a secure data

[51] Exhibit MEIU-20 (JDA-7).
[52] Sherman Direct, Case No. U-21389, p. 32-34.
[53] SolarEdge, "Grid Services and VPP Solution: The Grid of the Future, Today," available from https://www.solaredge.com/sites/default/files/grid-services-and-vpp-solution.pdf
[54] Stem, "Investor-owned Utilities: Flexible Solutions for Lower Risk and Greater Efficiency," available from https://www.stem.com/customers/investor-owned-utilities/.

exchange mechanism. Dr. Sherman also offered the following additional examples in her earlier testimony:[55]

1. Sacramento Municipal Utility District ("SMUD") and Sunverge partnership. This project demonstrates how intelligent energy storage technology, solar PV, and smart home devices can provide multiple grid management benefits while maximizing control for the utility. Sunverge successfully integrated energy storage technology with SMUD's Demand Response Management System to automate DR events for customers on a time-of-use ("TOU") Critical Peak Pricing tariff. A key takeaway from the project was that the operational benefits from DERs are highly location-specific.[56]

2. Nuvve and San Diego Gas and Electric ("SDG&E"). Nuvve partnered with SDG&E to deploy a vehicle-to-grid ("V2G") aggregator technology to manage EV charging and discharging. Through this partnership, the electric school bus fleet equipped with V2G charging through Nuvve's platform can provide energy back to the grid during emergency load reduction events.[57]

[55] Sherman Direct, Case No. U-21389, p. 33-34.
[56] Sunverge, "SMUD and Sunverge Demonstrate the Potential of Aggregated Distributed Energy Storage & Solar," available from https://esa.stormship.com/project-profile/smud-and-sunverge-demonstrate-the-potential-of-aggregated-distributed-energy-storage-solar/
[57] Nuvve, "Nuvve Partners With San Diego Gas & Electric to Allow Electric School Buses to Give Energy Back to the Grid and Prevent Blackouts Through the Emergency Load Reduction Program (ELRP)," July 19, 2022, available from https://investors nuvve.com/news-releases/news-release-details/nuvve-partners-san-diego-gas-electric-allow-electric-school.

3. Omega Grid and SMUD. The city of Sacramento worked with Omega Grid to use a blockchain-based software service to test a hyperlocal EV charging program to track customer rewards. The pilot project offered blockchain-based tokens for charging vehicles when there is a surplus of solar power on the grid.[58]

I list all of her examples again here because it shows that Consumers had the benefit of them earlier but has not referenced them in its planning for this case and does not appear to have learned from them.

An additional example pertains to Pacific Gas and Electric Company ("PG&E"). PG&E is in the process of standing up its Automated Response Technology program. This program will support using residential smart technologies for DR, TOU, and/or load shifting. According to the Request for Information, these technologies will be used automatically to curtail or shift energy use away from the higher cost periods in the customer's TOU rate plan and to help mitigate periods of high electric demand on the grid. Some of the technologies in this program include smart thermostats, smart appliances, heat pump water heaters, EV chargers, and batteries.[59] Finally, PG&E specifically testified that they plan to solicit third-party innovative design ideas. These ideas include, "customer incentives (i.e., pay for performance, fixed payment, penalty), payment options (e.g., gift cards, check,

[58] Thill, D., "Chicago startup will help test hyperlocal electric vehicle incentive in California," Energy News Network, September 13, 2019, available from https://energynews.us/2019/09/13/chicago-startup-will-help-test-hyperlocal-electric-vehicle-incentive-in-california/

[59] *Automated Response Technology Program Design*. Pacific Gas and Electric Company. https://www.pge.com/content/dam/pge/docs/about/doing-business-with-pge/2023-COA-RFI-215846-Atmtd-Rspns-Tchnlgy-Prgrm.pdf.

cash, gamification), payment terms (i.e., post event, monthly, annual), technology manufacturer fees, new technology intake process, and marketing strategies and tactics."[60]

**Q. Are there potential advantages to third-party-owned and -operated DER management services over utility-owned and –operated DERMS?**

A. Yes, there are several. The first, and most obvious, advantage is that outsourcing the ownership and operation of DER management services can save a utility, and more specifically, ratepayers, significant upfront costs for hardware, software, and infrastructure. Second, if the DERMS is managed by a third party, the utility does not need to educate and train its employees on a new system. Third, the third-party DERMS owner/operator is responsible for maintaining the system, avoiding further costs and responsibility for the utility. Last, but not least, employing a third party for this role would likely enable a utility to pilot a DERMS in a specific area at a lower cost than if it owned and operated the DERMS itself. Such a pilot would also help a utility evaluate a third-party provider before committing to a system-wide DERMS.

**Q. Are other utilities already successfully partnering with third parties to establish broad DER management services?**

A. Yes. Dr. Sherman identified in her earlier testimony several utilities employing third-party solutions for DERMS.[61] Again, I rely on her examples to show that Consumers had the

[60] 2024-2027 Demand Response Proposals of Pacific Gas and Electric Company, Case No. A.22-05-, p. 3-36. Available at https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/4857/474109675.pdf

[61] Sherman Direct, Case No. U-21389, p. 35-36.

benefit of these examples earlier but apparently opted not to learn from them. Dr. Sherman's examples include:

1. National Grid (working with Opus One Solutions): National Grid worked with Opus One Solutions in New York to provide a technical and financial platform for DERs using the GridOS Transactive Energy Management System.[62]

2. National Grid (working with EnergyHub): National Grid centralized its "Bring Your Own Device" programs using EnergyHub's Mercury DERMS. The company is also using the platform for enrollment, forecast-based dispatch, and reporting and settlement capabilities for its commercial and industrial resources.[63]

3. Con Edison (working with Smarter Grid Solutions): Con Edison integrated Smarter Grid Solutions' Strata Grid and Cirrus Flex platforms with the utility's systems and control room processes. These third-party solutions allowed Con Edison to automate optimized and aggregated dispatch of utility-scale energy storage systems and trading of any residual capabilities in the wholesale market.[64]

[62] Opus One Solutions, "Launching the World's First Transactive Energy Market at National Grid," available from https://www.opusonesolutions.com/customers projects/launching-the-worlds-first-transactive-energy-market-at-national-grid/.
[63] O'Leary, K., "National Grid selects EnergyHub as the platform provider to enhance its Bring Your Own Device demand response program," May 30, 2018, available from https://www.energyhub.com/blog/national-grid-bring-your-own-device-demand-response-program/.
[64] Smarter Grid Solutions, "Endurant (Con Edison)," available from https://www.smartergridsolutions.com/media-center/case-studies/endurant-con-edison.

**Q. What are your recommendations regarding the Company's proposed DER Optimization initiative?**

A. Consumers' DERMS proposal in this rate case is its fifth successive DERMS proposal in as many years. Despite the Commission having provided direction on what is necessary to demonstrate the prudency of a Company-owned and –operated DERMS, Consumers has repeatedly not met that bar. To avoid seeing a sixth, seventh, eighth, etc., DERMS proposal from the Company, I recommend that unless the Company explicitly commits to voluntarily undertake the workshops I recommend and cover the topics I recommend, that the Commission very clearly direct Consumers to initiate and organize the workshops I suggest along with the specific issues to be considered. Alternatively, the Commission could direct Staff to initiate and organize the workshops—specifically focused on Consumers' DERMS proposals. Regardless of who organizes the workshops, the organizer should cast a wide net to ensure participation in the workshops and be sure to invite trade associations, DER aggregators, and third-party DERMS providers. Doing so will enable the Company to gain a more holistic understanding of DERMS in all of its forms.

I have described in my testimony the issues and areas that any future DERMS proposal should address. These topics are suitable for any workshops as well. At a minimum the Commission should direct Consumers to be prepared to discuss in any such workshops forecasted DER adoption, regional or technical limitations around controlling DERs, and the potential impacts on DER owners. Workshops topics should also include identifying the challenges the Company seeks to solve and the desired program benefit.

If the Company eventually hires a consultant to assist in developing its DERMS, I recommend that the Commission direct the Company to engage a consultant with experience in the area of DERMS development. Although Consumers indicates it intends to engage an "industry-leading consultant,"[65] a discovery response in this case indicates it does not seem concerned with whether the consultant has any minimum level of experience with DERMS.[66] If a time comes when Consumers can sufficiently demonstrate the reasonableness and prudency of a plan to implement a DERMS, any consultant engaged to do so should have experience successfully developing and implementing a DERMS for a utility substantially similar to Consumers.

Because these technologies are new to Consumers, it is entirely reasonable and logical to direct the Company to work with and learn from stakeholders with experience in other states with other utilities. After engaging those most likely to interact with any DERMS it develops, Consumers may recognize better ways to serve its customers and owners of DERs.

## III. EQUIPMENT INVENTORY

**Q. Earlier you referenced the development of a proposal pertaining to hardware with long acquisition lead times. Please provide more information about that.**

A. I should first explain that the impetus for the proposal stems from Consumers' own statements about long lead times for some equipment as well as my own experience with

[65] McPhail II Direct, Case No. U- 21585, p. 85.
[66] Exhibit MEIU-21 (JDA-8).

United's members. In discussing delays in the development of solar projects, Company witness Thomas Clark describes as a challenge longer acquisition lead time for key components, such as transformers.[67] Company witness Keith Kurdziel provides greater detail about the lead times for transformers, indicating that it can take two years to obtain one.[68] Company witness Jeffrey Myrom confirms this timeframe for ordering transformers. In his discussion of EV direct current fast charging facilities, he notes that "transformers ... are backordered nearly 24 months and wait times are trending longer, not shorter."[69] This testimony is consistent with my own experience. In the course of my duties, including interactions with members about the challenges they face, I have learned that substantial delays concerning the availability of transformers is a significant problem.

As Consumers itself recognizes, interconnecting new DER and EV charging stations can involve the need for additional and/or larger transformers. Timely access to and installation of transformers is important to ensure project development proceeds reasonably. However, this problem does not just affect utilities and developers. More importantly, it also affects Michigan's ability to meet its statutory clean energy standard of 80% between 2035 and 2039 and 100% by 2040.[70] The initial 80% standard is only 11 years away. With lead times for new transformers necessary to accommodate the interconnection of clean energy resources being at least two years, the Commission should consider steps to mitigate such delays to ensure Michigan can reach its statutory standards.

[67] Direct Testimony of Thomas P. Clark on behalf of Consumers Energy Company, Case No. U- 21585, p. 28.
[68] Direct Testimony of Keith M. Kurdziel on behalf of Consumers Energy Company, Case No. U- 21585, p. 49.
[69] Direct Testimony of Jeffrey A. Myron on behalf of Consumers Energy Company, Case No. U- 21585, p. 51.
[70] Public Act 235 of 2023.

**Q. What are you proposing to address this problem?**

A. Given the years-long delay to acquire necessary hardware, I recommend that the Commission direct Consumers to identify, prior to its next general electric rate case, hardware commonly associated with interconnecting advanced energy technologies, like DERs and EV charging facilities, that have long acquisition lead times. Anticipated needs in light of statutory goals and expected electrification trends over at least the next 10 years should be considered. After having done so, to the extent that Consumers does not maintain an adequate inventory of transformers and other such equipment for the timely development and installation of advanced energy technologies, Consumers should then develop and propose in its next general electric rate case a system for maintaining an inventory of such equipment. To be clear, I am not recommending that Consumers change its equipment ordering practices at this time. I am simply proposing that Consumers evaluate the need to do so to ensure that it has adequate supplies on hand to timely accommodate the ongoing energy transition. Reviewing this study will help the Commission and stakeholders evaluate the merits of maintaining such an inventory. Elements to consider include potential costs savings, deployment timelines, grid reliability, and maintaining a consistent forward trajectory toward Michigan's meeting its goals to decarbonize its energy and electrify the transportation sector.

## IV. CONCLUSION

**Q. Please summarize your recommendations to the Commission.**

A. I recommend that the Commission:

1. Reject Consumers' request for the deployment of DERMS-related hardware and software.
2. Direct Consumers to finish their business planning, benchmarking, and learning before requesting ratepayer dollars for any kind of DERMS implementation.
3. In the absence of an explicit voluntary commitment, explicitly direct Consumers to organize and engage in stakeholder workshops covering the specific issues discussed in the above testimony. Alternatively, the Commission could direct Staff to initiate and organize the workshops with specific focus on Consumers' proposed DERMS implementation.
4. Explicitly direct Consumers to develop and share a business case for DERMS covering the issues discussed in the above testimony.
5. Direct Consumers to identify the hardware commonly associated with interconnecting advanced energy technologies with long acquisition lead times and prepare for inclusion with its next general electric rate case a proposal for maintaining an inventory of such equipment to accommodate the timely development and installation of advanced energy technologies.

**Q. Does this conclude your direct testimony?**

A. Yes.

**STATE OF MICHIGAN**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

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| | | |
|---|---|---|
| In the matter of the application of **Consumers Energy Company** for authority to increase its rates for the generation and distribution of electricity and for other relief. | ) ) ) ) ) | **Case No. U-21585** |

**Direct Exhibit List of MEIU**

| Witness | Exhibit # | Exhibit Description |
|---|---|---|
| Dr. Laura S. Sherman | MEIU-1 (LSS-1) | Résumé of Dr. Laura S. Sherman |
| Dr. Laura S. Sherman | MEIU-2 (LSS-2) | Discovery response MEIU-CE-0092 |
| Dr. Laura S. Sherman | MEIU-3 (LSS-3) | Discovery response MEIU-CE-0071 |
| Dr. Laura S. Sherman | MEIU-4 (LSS-4) | Discovery response MEIU-CE-0073 |
| Dr. Laura S. Sherman | MEIU-5 (LSS-5) | Discovery response MEIU-CE-0072 |
| Dr. Laura S. Sherman | MEIU-6 (LSS-6) | Discovery response MEIU-CE-0261 |
| Dr. Laura S. Sherman | MEIU-7 (LSS-7) | Discovery response MEIU-CE-0076 |
| Dr. Laura S. Sherman | MEIU-8 (LSS-8) | Discovery response MEIU-CE-0075 |
| Dr. Laura S. Sherman | MEIU-9 (LSS-9) | Discovery response MEIU-CE-0258 |
| Dr. Laura S. Sherman | MEIU-10 (LSS-10) | Discovery response MEIU2-CE-0257 |
| Dr. Laura S. Sherman | MEIU-11 (LSS-11) | Discovery response MEIU-CE-0080 |
| Dr. Laura S. Sherman | MEIU-12 (LSS-12) | Discovery response MEIU-CE-0263 |
| Dr. Laura S. Sherman | MEIU-13 (LSS-13) | Discovery response MEIU-CE-0506 |
| John D. Albers | MEIU-14 (JDA-1) | Résumé of John Albers |
| John D. Albers | MEIU-15 (JDA-2) | Discovery Response U-21585-MEIU-CE-0083 |
| John D. Albers | MEIU-16 (JDA-3) | Discovery Response U-21585-MEIU-CE-0371 |

| | | |
|---|---|---|
| John D. Albers | MEIU-17 (JDA-4) | Discovery Response U-21585-MEIU-CE-0568 |
| John D. Albers | MEIU-18 (JDA-5) | Discovery Response U-21585-MEIU-CE-0375 |
| John D. Albers | MEIU-19 (JDA-6) | Discovery Response U-21585-MEIU-CE-0082 |
| John D. Albers | MEIU-20 (JDA-7) | Discovery Response U-21585-MEIU-CE-0374 |
| John D. Albers | MEIU-21 (JDA-8) | Discovery Response U-21585-MEIU-CE-0084 |

**STATE OF MICHIGAN**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

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| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for<br>the generation and distribution of<br>electricity and for other relief. | )<br>)<br>)<br>)<br>)<br>) | **Case No. U-21585** |

# EXHIBITS OF DR. LAURA S. SHERMAN

**ON BEHALF OF**

**THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL,**

**INSTITUTE FOR ENERGY INNOVATION,**

**AND**

**ADVANCED ENERGY UNITED**

# LAURA S. SHERMAN, Ph.D.

cell: 607.592.3026
laura@mieibc.org

## PROFESSIONAL EXPERIENCE:

April 2019 – present **Michigan EIBC/IEI**, Lansing, MI **President**

- Organize and lead a staff of five employees, contractors, and student interns.
- Work with and inform each organization's Board of key decisions, upcoming events, long-term strategy, etc.
- Fundraise and coordinate both organization's annual budgets.
- Represent Michigan EIBC in the media, at the legislature, with regulators, and with the state administration in collaboration with a broad coalition.
- Conduct event planning including for annual conferences, networking events, tours, and legislative networking opportunities.
- Develop regulatory and legislative policy positions to support advanced energy businesses.
- Engage with the Michigan Public Service Commission and Michigan legislature on behalf of member companies.

Oct. 2017-March 2019 **Michigan EIBC/IEI**, Lansing, MI **VP for Policy Development**

- Develop regulatory and legislative policy positions to support advanced energy businesses.
- Coordinate regulatory interventions and engagement in regulatory stakeholder processes among member companies.
- Engage with the Michigan Public Service Commission and Michigan legislature on behalf of member companies.
- Support policy initiatives focused on wind energy, solar energy, electric vehicles, storage, taxation, and corporate purchasing of renewable energy.
- Represent Michigan EIBC in the media, at the legislature, with regulators, and with the state administration in collaboration with a broad coalition.
- Conduct event planning including for annual conferences, networking events, tours, and legislative networking opportunities.

Feb. 2017-March 2019 **5 Lakes Energy**, Lansing, MI **Senior Consultant**

- Research, analysis, communication, and advocacy surrounding complex energy issues.
- Lead wind and solar siting project to address opposition to deployment in coordination with philanthropy, industry, and stakeholders across nine Midwest states.
- Focus areas include renewable energy development, community engagement, stakeholder coordination, business sustainability, and electric vehicles.
- Support newsletter, website, and social media communications.

April 2015-Dec. 2016 **U.S. Senate**, Washington, DC **Legislative Assistant/Policy Advisor**

- Policy advisor to Senator Michael Bennet (D-CO) on agriculture, energy, environment, land, and natural resource issues.
- Legislative topics included: farming and ranching, public land conservation and management, water policy, energy development, renewable energy including energy tax incentives and transmission permitting, energy efficiency, endangered species, climate change, sportsmen's issues, environmental pollution and regulations, air quality, and biofuels.

- Drafting legislation; building coalitions; negotiating policy solutions; writing speeches; staffing the Senator at hearings of the Agriculture and Finance Committees.

2014-2015 **U.S. Senate**, Washington, DC **AAAS Congressional Science Fellow**

- Competitively selected AAAS Fellow sponsored by the American Geophysical Union. Served in the Office of Senator Michael Bennet (D-CO).
- Drafting legislation; helping to facilitate political coalitions; meeting with constituents; interacting with federal agencies; delivering policy briefings and recommendations.

2012-2014 **University of Michigan**, Ann Arbor, MI **Postdoctoral Research Fellow**

- Successfully obtained competitive grant funding for novel method to track air pollution from power plants and metal smelters into rainfall across the Great Lakes region.
- In collaboration with epidemiologists, developed and utilized new methods to assess the sources and pathways of human exposure to mercury pollution.
- Published five manuscripts; presented talks and organized scientific sessions at national and international conferences.

2007-2012 **University of Michigan**, Ann Arbor, MI **Graduate Researcher**

- Competed for and received National Defense Science and Engineering Graduate Fellowship and Graham Environmental Sustainability Institute Doctoral Fellowship.
- Developed groundbreaking methods to "fingerprint" mercury pollution from coal-fired power plants and trace it into rainfall, lake sediments, and fish.
- Published eight manuscripts, was interviewed for "The Environment Report" on NPR and general-circulation science magazines, presented research at national and international conferences.
- Ph.D. dissertation received university-wide ProQuest Distinguished Dissertation Award and departmental John Dorr Graduate Academic Achievement Award.

2005-2007 **Massachusetts Institute of Technology**, Boston, MA **Research Scientist**

- Found evidence for early life on Earth in ancient rocks. Published two manuscripts.

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## SERVICE & LEADERSHIP:

2021-present **Board Member** of Zero Emission Transportation Association Education Fund Board
2020-present **Board Member** of University of Michigan Earth and Environmental Sciences Alumni Board
2019-2020 **Board Member** of Advancing Women in Energy
2017-2019 **Communications Chair** for Advancing Women in Energy
2013-2014 **Supported** the Ann Arbor Energy Commission on community solar projects
2009-2014 **Peer reviewer** of more than 20 scientific manuscripts
2009 **Initiator and organizer** of new departmental seminar series, University of Michigan
2008-2010 **President** of department student organization (GeoClub), University of Michigan
2008 **Lead organizer** of Michigan Geophysical Union Poster Conference
2007-2008 **Department Steward** to Graduate Employees Union, University of Michigan

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## EDUCATION:

**Ph.D.** 2012 Earth and Environmental Sciences, **University of Michigan** (GPA: 8.837 out of 9.0)

**B.S.** 2005 Geological and Environmental Science, **Stanford University** (GPA: 4.007 out of 4.33)

**Question:**

1. Did Consumers Energy conduct a benefit-cost analysis for its proposed EV programs?

a. If so, please provide all of the assumptions, quantified costs and benefits, and criteria included in the benefit-cost analysis.

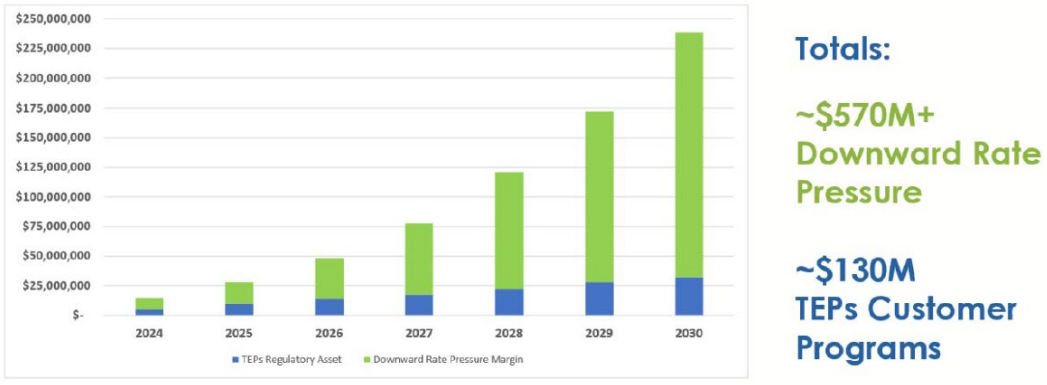
b. If so, please provide all results of the benefit-cost analysis.

c. If so, please describe all of the cost tests undertaken to conduct the benefit-cost analysis.

**Response:**

1. Yes.
   a. Please see Exhibit A-153 (JAM-3), which details the costs and revenues from optimized EV load growth via the TEP customer programs.

   b. Per Exhibit A-153 (JAM-3), the positive and increasing values each year clearly show that the additional load growth from EVs creates margin that exceeds the TEP customer program revenue requirement and other costs. The cost test shows that the TEP customer programs do not increase rates but instead create downward rate pressure for all customers while optimizing EV load. In fact, there is significant additional margin from optimized EV load growth, even without considering other potential non-rate benefits such as, but not limited to, equitable access to charging, economic development, job creation impacts, and reduced pollution and health impacts. Graphically, the results of this workpaper are also illustrated in the Executive Summary of the Company's TEP report, copied below.




   c. Per Exhibit A-135 (JAM-3), the cost test compared revenue from EV loads against the costs of the revenue requirement, energy, capacity, transmission, and distribution.

**Witness:** Jeffrey A. Myrom
**Date:** July 23, 2024

**Question:**

2. According to witness Myrom, the Company is "maintaining the PowerMIDrive Residential program as approved in Case No. U-21224, maintaining the PowerMIDrive Public Charging and PowerMIFleet programs as approved in Case No. U-21389."

a. For the PowerMIDrive DCFC rebates approved in Case No. U-21389:

i. How much funding remains unspent?

ii. How much funding remains unallocated?

iii. How much funding has been allocated to DCFC sites but not yet spent?

iv. How many more DCFC rebates (beyond the spent and allocated funds) could the approved funding support?

**Response:**

a. For context, the DCFC rebates were approved in two phases of $4.25M in combined rebates and make ready for the first 37 approved, followed by an approval of $11M in combined rebates and make ready for an additional 100, for a projected total of 137 DCFC site incentives via $15.25M in total expenditures.

i. Of the $15.25M in total expenditures approved, $10.63M has not yet been dispersed to customer host sites in progress.

ii. None. We have customer host sites allocated for all 137 projected rebates and anticipate that this will utilize the remaining $10.63M. For context, many early sites were combinations of lower powered DCFCs (e.g. 50-62.5 kW), and we are now requiring 150 kW or greater given market conditions, which are anticipated to have higher make ready costs on average.

iii. Same as "i" above: $10.63M.

iv. At this time, we anticipate that the remaining 72 host sites in progress (of the 137 projected total) will utilize all funds. However, if projects run below fiscal projections the Company plans to distribute all remaining funds. Thus, it is possible, but presently unlikely, that funding will allow for slightly more than 137 DCFC sites.

**Witness:** Jeffrey A. Myrom
**Date:** July 16, 2024

**Question:**

4. Consumers has 137 public DCFC sites in its territory that are either now operational or under development.

a. How many public DCFC ports will this total?

b. What percentage of these ports are/will be along highways/travel corridors versus deployed within communities?

c. How many of these ports are deployed with underserved and/or Justice40 communities?

**Response:**

a. The Company anticipates that when all 137 public DCFC sites are complete that approximately 324 fast charging ports will be in operation.

b. All sites will be within 5 miles of a travel corridor, and thus the Company anticipates that 100% will serve travel corridors. Enabling a fast-charging network for long-distance travel is the intention of the original DCFC pilot and it has been maintained throughout the selection criteria for host site rebates.

c. Utilizing the Justice 40 map, "Electric Vehicle Charging Justice40 Map (arcgis.com)," 24 ports are presently deployed within Justice 40 areas. Those ports include:

| DCFC IN J40 REGION | TOTAL PORTS |
|---|---|
| Mackinaw City Odawa Casino | 4 |
| West Branch Dean Arbour Ford | 2 |
| West Branch Ace Hardware | 2 |
| Mt Pleasant Pizza King | 2 |
| Mt Pleasant Citgo/Coyne Oil | 2 |
| Greenville Log Cabin Marathon | 2 |
| Saginaw Family Dollar | 2 |
| Saginaw City of Saginaw | 2 |
| Marshall Johnny's Markets | 2 |
| Adrian Morning Fresh Bakeries | 4 |
| **TOTAL** | **24** |

Furthermore, there are an additional 22 ports in close proximity to Justice 40 areas. Those ports include:

| DCFC IN CLOSE PROXIMITY TO J40 REGION | TOTAL PORTS |
|---|---|
| Petoskey Blarney Castle | 2 |
| Clare Blarney Castle | 2 |
| Clare Witbecks Family Foods | 3 |
| Reed City ACE Hardware | 2 |
| Cadillac J&H Market | 2 |
| Manistee Blarney Castle | 2 |
| Fruitport Meijer | 2 |
| Grand Rapids Meijer | 2 |
| Jackson Airport | 3 |
| Battle Creek Citgo | 2 |
| **TOTAL** | **22** |

**Witness:** Jeffrey A. Myrom
**Date:** July 16, 2024

**Question:**

3. Witness Myrom, p. 9-10: In (5), witness Myrom proposes a new rebate for public and fleet DCFCs that utilize battery arbitrage.

a. Why would "such host site projects" not qualify for the CIAC waiver?

b. Could this new rebate ($40,000) be combined with another Company rebate (e.g., a PowerMIDrive public charging rebate) such that the customer would receive $80,000 in funding for a DCFC with battery arbitrage?

c. At $40,000 per rebate, what is the expected cost for this program and over what time horizon?

i. How many DCFCs with battery arbitrage does Consumers expect to deploy over what time horizon?

1) How many of these DCFCs does the Company expect will be public DCFCs?

d. Why is Consumers only proposing new rebates for DCFC ports that use battery storage and not proposing new funding for additional DCFC chargers that do not use battery storage? Please provide all evidence, documentation, and analysis used to reach your conclusions.

e. Is there a limit on the number of public or fleet DCFC rebates a single applicant can apply for?

i. If so, is this limit based on a certain time period (e.g., two applications per 12- month period)?

f. Is there a limit on the total number of DCFCs that can be deployed at a single site and receive a rebate?

**Response:**

a. The CIAC waiver is temporary and intended to cover sites until all previously approved make ready funds are expended. The Company anticipates that all projects funded via the pilot phase will be complete before any battery-integrated DCFC rebates are disbursed to customer host sites. Thus, there is no anticipated overlap of the temporary pilot phase funding and CIAC waiver with the proposed battery-integrated DCFC rebate under the permanent programs. For example, if the battery-integrated DCFC rebate is approved by the MPSC, that would likely occur in Q2 of 2025 and host sites would most likely begin to receive rebate funding in 2026 given construction schedules.

b. As I interpret your question given the $80K example (e.g. 2 x $40K rebates), yes. The Company's intention is to allow multiple rebates per site. Thus, a site with four battery-integrated DCFCs could receive a rebate up to $160,000 (e.g. 4 x $40K). The Company's intention is also to allow Level 2 (L2) rebates at the same site if applicable. For example, a school bus fleet of 30 electric busses could apply for 30 L2 rebates and a battery-integrated DCFC rebate for emergent use to support the clean transportation of children.

c. The costs will be maintained as a subset of the approved TEP budget and balanced against the results of other EV load management incentives. As stated in prior filings, the Company intends to revisit market conditions and program results annually and will allocate the TEP budget to best optimize EV load. Nevertheless, at this time, we estimate that 40 or more rebates per year, equivalent to $1.6M

or more per year, could be awarded starting in 2026 (again this timing assumes MPSC approval in Q2 2025 and subsequent construction schedules).

i. If we award 40 per year on average from 2026 through 2029, 160 battery-integrated DCFCs are possible in the near-term launch of the program.
   1) The market will determine this, but we estimate that it could be nearly an even split between public DCFCs and fleets with emergent charging needs.

d. The rationale for why DCFC rebates are not presently proposed is the same that was shared in prior rate cases. The State of Michigan is in the midst of disbursing approximately $110M in Federal NEVI funds for fast charging sites approximately every 50 miles along major travel corridors. The Company intends to revisit market conditions once NEVI awards near completion to see if areas remain that lack fast charging infrastructure and if fast charging infrastructure is pacing with EV adoption. The Company remains open to public DCFC rebates in the future depending on market conditions or significant policy changes (e.g. presently unspent NEVI funds are cancelled by the Federal government). As for rebates for battery integration with DCFCs, fast charging is the one segment that presently does not have load management opportunities that would be acceptable to the EV customer experience without the use of energy storage and arbitrage. Furthermore, we anticipate that market demand for DCFCs will require a significant increase in make ready infrastructure like transformers, and fast charging is a rapidly growing load segment as was shown in the Company's TEP filing and public meetings (e.g. the potential for 1,500 fast charging sites of 1 MW or greater by 2030). Thus, battery integration is anticipated to help address load management and make ready constraints, especially in rural areas with intermittent traffic and less charging and distribution infrastructure. Consumers electric territory covers wide swaths of rural areas. In sum, the Company remains very open to optimizing fast charging infrastructure from an access and load perspective, and will continually revisit this in future rate cases, settlements, and TEP filings.

e. No, but as with all TEP programs, the Company will work to distribute rebates and infrastructure across our electric territory.

f. No, but as previously noted in the permanent TEP program proposals, the Company will balance the TEP budget to help optimize load management across all segments. If budget constraints arise, the Company will prioritize residential and income-qualified programming.

**Witness:** Jeffrey A. Myrom
**Date:** July 18, 2024

**Question:**

5. According to the Company's response to MEIU-CE-0076, Consumers estimates that a $40,000 per battery-integrated DCFC port rebate will cover approximately 20% of project costs.

a. Does Consumers expect the private market will fund the remaining 80% of project costs?

b. Please share all calculations and data used to determine the level of this proposed DCFC rebate.

**Response:**

a. Yes, though we also anticipate that host sites will continue to pursue any available government funding opportunities as they are today.

b. Per Figures 5 and 6 of the Company's June 2024 TEP report (0688y00000EFQgtAAH (site.com)), the average cost per site ($191K) and make ready ($45K) is near $237K. Assuming some inflation and other contingencies, an estimate of $250K for a 150 kW DCFC project starting in 2026 (again assuming rebate approval in mid-2025 and construction schedules commencing approximately 6 months afterwards) is reasonable for the planning level example given in MEIU-CE-0076. If the $40K rebate fully covers the additional cost of the 400 kWh of battery storage for the DCFC (again assuming $100 per kWh of storage), and the battery eliminates make ready costs, then the total cost could be closer to $200K per 150 kW of DCFC. 400 kWh of battery storage is equivalent to approximately 8 EVs charging sequentially that utilize 50 kWh each. If an average session is 30 minutes, that is equivalent to approximately 4 hours of continuous fast charging without significant draw from the grid. Moreover, if just a mere 50 kW of capacity from the grid is supplemented by the battery output, then it is possible that that the battery integration could provide energy arbitrage for approximately 8 hours of continuous charging. In locations with intermittent traffic or seasonal utilization, it is likely that full off-peak arbitrage is possible. Furthermore, if battery prices continue to decrease, then it is also possible that even longer operating hours could occur utilizing such energy arbitrage because even more kWh of storage would be unlocked with the rebate.

**Witness:** Jeffrey A. Myrom
**Date:** August 14, 2024

**Question:**

7. Consumers estimates in its TEP (filed in U-21538 and referenced in this docket by witness Myrom) that the average cost of a DCFC project is $191,239, not including make ready costs.

a. Is this average cost per DCFC port or per site?

i. If per site, what is currently the average number of DCFCs per site in Consumers territory across the 137 sites?

b. Consumers also estimates in its TEP that the average cost of DCFC make ready expenditures was $45,509. Is this per port or per site?

c. If Consumers offers a $40,000 rebate per DCFC port, what percentage of the total average project cost does Consumers estimate this will cover?

**Response:**

a. Per site.
    i. To date, there have typically been two DCFCs per site.
b. Per site.
c. The Company anticipates that this will primarily cover the cost of the battery integration and reduce make ready costs on top of that. For example, if battery storage costs are near $100 per kWh, then a $40K rebate could support up to 400 kWh of storage. This in turn could reduce make ready costs below $45K per site, especially in intermittent areas where the draw from a battery-integrated DCFC could potentially be like a high-power L2 or a low-power DC charger. Thus, we believe there will be situations where the rebate for battery-integration unlocks a higher-power fast-charging experience for the customer, avoids a portion of make ready costs, minimizes demand charges, and allows for energy arbitrage via a TOU rate. The total benefits of this rebate will be site specific, but they are clearly helpful to both the utility, from a load management and make ready workload perspective, and the host site via both project and operating cost reductions. In sum, assuming a total project cost of approximately $250K from today's averages, and assuming that the rebate fully covers the additional cost of battery-integration, a $40K rebate could bring project costs closer to $200K per site, or approximately a 20% project cost reduction with on-going site-specific operating cost reductions. As with all our TEP rebate programs, the Company plans to continue to monitor actual project outcomes to determine if modifications to the proposed rebate are needed in the future.

**Witness:** Jeffrey A. Myrom
**Date:** July 17, 2024

**Question:**

6. According to witness Myrom (p. 8), Consumers projects that it will receive 1,521 to 1,854 public DCFC service requests between now and 2030.

a. Does the Company expect that all of these projects will use battery storage systems and will therefore rely on Consumers new rebate proposal?

i. If not, what percentage of these requests does Consumers project will use battery storage systems for energy arbitrage?

b. Where within its territory does Consumers expect these public DCFC ports to be deployed?

c. Beyond the approved PowerMIDrive rebate program that the Company does not propose to expand in this case, does Consumers have any other incentives available that could support the deployment of publicly available DCFCs?

i. If yes, please provide detailed information about these programs including links to any websites describing the programs.

**Response:**

a. No.
    i. As a baseline, 160 rebates for battery-integrated DCFCs between 2026 and 2030 would be approximately 10%.
b. The Company expects that the majority of battery-integrated DCFCs will be placed along or near travel corridors, especially in rural and other areas that have intermittent traffic and lower utilization.
c. No. However, outside of incentives the Company is preparing to help speed such service requests by forecasting likely market demand for new DCFC sites and pre-ordering infrastructure. Timely service is a huge benefit to DCFC deployments.

**Witness:** Jeffrey A. Myrom
**Date:** July 17, 2024

**Question:**

2. According to the Company's response to MEIU-CE-0072, Consumers is not proposing DCFC rebates at this time because Michigan is receiving $110M in federal funding to deploy DCFCs along highways.

a. How many DCFCs does Consumers expect the NEVI funding will support deploying in its territory over the next 5 years?

b. Does Consumers expect that a portion of the NEVI funding will support DCFC ports at retail/community locations (as opposed to on Alternative Fuel Corridors)?

i. If yes, please provide evidence to support this expectation.

ii. If yes, when does Consumers expect that NEVI funding in Michigan will be dedicated to support DCFC ports at retail/community locations (i.e., what year?)?

c. Assuming that public DCFC will be needed at retail/community locations (and not only along major highways), does Consumers anticipate that DCFC at these locations will be needed later (in future years) rather than in the near-term?

i. If so, please provide all evidence used to reach this conclusion.

**Response:**

a. According to the Michigan Department of Transportation's (MDOT) website (see National Electric Vehicle Infrastructure Formula Program (michigan.gov)), 39 sites were selected in Round 1, Round 2 selections to fill 43 additional gaps are anticipated in January 2025, and additional rounds will occur after that through Fiscal Year 2026 as necessary. Each fast-charging NEVI site will have at least 4 x 150 kW ports, but it is possible that some will have more. These are not Company owned developments and thus we do not have exact details regarding the total number of ports. Nonetheless, by early 2025, MDOT's implementation of NEVI funds should reveal how more than half of the NEVI funds will be utilized. Moreover, we estimate that a minimum of 328 fast charging ports should be underway (39 sites from Round 1 plus 43 sites from Round 2 totals 82 sites, and 82 sites times a minimum of 4 ports per site is at least 328 ports).

b. The Company does not know what the final selections by MDOT will be.

c. The Company does not see evidence that fueling centers (including but not limited to gas stations, convenience stores, grocery stores with gas pumps, truck stops, and big box stores with gas pumps) would not continue to fuel vehicles in the future regardless of where that energy may come from (e.g. a transition from gasoline to electricity). It is presently a core business for such commercial establishments and absent Americans foregoing their automobiles (which seems highly unlikely) we expect it to remain a core business. Thus, we expect that such commercial locations will continue with their fueling business in the future. Regarding how many of the aforementioned fueling centers are along travel corridors versus deeper in communities, we do not know.

i. On a per mile basis fast charging is a similar cost to gasoline. People are willing to pay the price of gasoline today, so if a market substitute (electricity) is a similar price then we see no reason that charging while on the road would suddenly be shunned and lead to the demise of fueling centers.

**Witness:** Jeffrey A. Myrom
**Date:** August 7, 2024

**Question:**

1. According to the Company's response to MEIU-CE-0073, Consumers has deployed or is in the process of deploying 324 public DCFC ports at 137 sites. According to the Company's response to MEIU-CE-0072, the Company anticipates another 160 rebates for battery-integrated DCFCs from 2026 to 2029, with only 50% of those being public DCFCs.

a. Please confirm, based on these discovery responses, that the Company anticipates awarding funding to deploy 404 public DCFC ports by 2030.

i. If not confirmed, please provide calculations as to the correct number of public DCFC ports for which the Company anticipates providing funding by 2030.

b. Please confirm that the Company estimates that 5,000 public DCFC ports will be needed in its territory by 2030.

i. If not confirmed, how many public DCFC ports does the Company estimate will be needed in its territory by 2030?

c. How does the Company expect the remaining ~4,596 public DCFC ports will be funded?

i. Does the Company anticipate any public funds (state or federal) will be utilized?

ii. Does the Company anticipate that future utility funds will be utilized?

**Response:**

For clarification, in MEIU-CE-0072, I said that "The market will determine this, but we estimate that it could be nearly an even split between public DCFCs and fleets with emergent charging needs", regarding the potential for how battery integrated DCFC rebates may happen. EV charging infrastructure is still very much in the early stages and false precision should not be assumed. As stated before, the Company will continue to evaluate market conditions and adjust our TEP if necessary, depending upon how the market plays out.

a. This is an approximate estimate that the Company believes is possible assuming approval of a battery integrated DCFC rebate by the MPSC.
b. Confirmed using the 500,000 EVs by 2030 scenario.
c. The Company expects that the fast-charging market will transition from needing supplemental funding such as NEVI, to sustainable development independent of grants and rebates. The Company does recognize that additional support may be necessary in the interim. As previously stated, we plan to re-evaluate market conditions as the NEVI funding results become more clear.
    i. If public funds are available, the Company expects that host sites will continue to apply for such funding.
    ii. For battery-integrated DCFCs, yes, and especially in areas with intermittent and seasonal fluctuations in traffic.

**Witness:** Jeffrey A. Myrom
**Date:** August 7, 2024

**Question:**

11. According to witness Clark, the new option to provide land lease payments as bill credits arose because of interest from the Michigan Department of Natural Resources.

a. Please detail why exactly an option to take lease payments as bill credits is of interest to Michigan DNR.

b. Would this option provide cost savings to the State of Michigan? If so, please detail exactly the manner of these cost savings.

**Response:**

a. The DNR has requested the Company to pay potential future lease agreements with bill credits to ensure the lease payments are used to cover operating expenses.

b. No. As previously stated, this option is to ensure the lease payments are used to cover operating expenses.

**Witness:** THOMAS P CLARK
**Date:** July 17, 2024

**Question:**

2. On page 181 of Donald A. Lynd's testimony, it is stated that "smart meter unit costs increased in 2022 and 2023 due to the purchase of more polyphase meters and a 5% pricing surcharge associated with significant increases in the vendor's costs."

a. Please clarify if the "pricing surcharges" applied by the Company's current AMI vendor are planned or unplanned expenses?

b. If the answer to subpart (a) is unplanned, how is the Company preparing to avoid unforeseen surcharges in the future?

c. Given the multi-year planning horizon for the LVD metering subprogram, is the Company evaluating other AMI vendors?

i. If so, how is the Company benchmarking industry standards and capabilities?

ii. If not, can the Company provide its rationale for not evaluating industry

**Response:**

a. The pricing surcharges described on page 181 of my direct testimony were unplanned and were to cover increased costs of transportation and components.

b. Metering prices are now contractually set through 2032.

c. Yes. The present AMI technology deployed by the Company, including the collection engine, the system that interrogates the meters daily for billing determinants and meter events, is proprietary to a single vendor. The system and meters will not communicate with other vendor software, nor will the existing software communicate with other meter vendor products. That said, the Company is currently evaluating AMI technologies offered by both the present and other AMI vendors.

    i. Through the remainder of 2024, the Company is identifying and evaluating different scenarios for the future of its AMI technology, including but not limited to, maintaining the status quo, upgrading the existing vendor technology, switching to another vendor's products, or utilizing multiple vendor products and systems. After this work is complete the Company will benchmark the various options through the experiences of other utilities, vendors, and industry groups, such as the Edison Electric Institute (EEI).

    ii. No response required.

**Witness:** DONALD A. LYND
**Date:** August 13, 2024

**Question:**

2. Please refer to witness Lynd's response to 21585-MEIU-CE-0263. Witness Lynd stated that "Through the remainder of 2024, the Company is identifying and evaluating different scenarios for the future of its AMI technology, including but not limited to, maintaining the status quo, upgrading the existing vendor technology, switching to another vendor's products, or utilizing multiple vendor products and systems. After this work is complete the Company will benchmark the various options through the experiences of other utilities, vendors, and industry groups, such as the Edison Electric Institute (EEI)."

a. When did the Company begin the process of identifying and evaluating different scenarios for the future of AMI technology?

b. What different scenarios are under consideration for the future of AMI technology?

c. What hardware and software features and use cases are currently under consideration as part of this evaluation process? What is the Company's business case for future AMI technology?

d. Does the Company plan to include the Commission and stakeholders in this research and benchmarking phase?

    i. If the answer to subpart (d) is yes, describe the venue in which the Company plans to engage with the Commission and stakeholders on this matter.

**Response:**

a. The Company identified scenarios in 2023 and the analysis of each scenario began in 2024.

b. As provided in the response to U21585-MEIU-CE-0263, the Company is evaluating scenarios including maintaining existing technology (status quo), using a single meter vendor solution, and using a multiple meter vendor solution.

c. The Company is looking at similar functionality in use today including automated reading and remote turn-on/turn-off, as well as new functionality being offered such as grid-edge computing. The Company's business case, when developed, for future AMI technology will focus on technology obsolescence.

d. Yes, the Company will share the evaluations and recommendations with the Commission and stakeholders when the work is further vetted.

    i. The venue has not been decided yet as this work is still in the early stages. Previously, the Company has held technical conferences to engage with the Commission and stakeholders and it is possible that would be the forum for sharing this information. The Company's current evaluation of AMI technologies will not impact the AMI procurement decisions included in the timeframe covered in this case.

**Witness:** DONALD A. LYND
**Date:** August 27, 2024

**STATE OF MICHIGAN**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

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| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for authority to increase its rates for<br>the generation and distribution of<br>electricity and for other relief. | )<br>)<br>)<br>)<br>)<br>) | **Case No. U-21585** |

# EXHIBITS OF JOHN D. ALBERS

**ON BEHALF OF**

**THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL,**

**INSTITUTE FOR ENERGY INNOVATION,**

**AND**

**ADVANCED ENERGY UNITED**

# JOHN D. ALBERS

Williamsville, Illinois
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## PROFESSIONAL EXPERIENCE

**Director,** Advanced Energy United, *2023-present*
Monitor and oversee regulatory efforts related to advanced energy technologies in Illinois, Michigan, Indiana, and Wisconsin on behalf of United and assist with legislative and education efforts as needed.

- Develop policy positions in furtherance of goal of a 100% clean energy economy.
- Ensure that member interests are represented in public utility commission proceedings affecting markets for renewable energy, battery storage, electric vehicles, energy efficiency, demand response, virtual power plants, and related advanced energy technologies.
- Draft legislation, testimony, and public comments and oversee preparation of same supporting goal of a 100% clean energy economy.
- Educate regulators, legislators, state agency officials, candidates, and media on the benefits of advanced energy technologies.
- Coordinate efforts among aligned organizations to support opportunities for clean energy to power our economy.
- Oversee engagement and work by outside counsel and consultants.

**Policy Advocate,** SunPower, Policy & Strategy, *2022-2023*
Monitor and influence legislation, rules, and regulatory proceedings impacting the residential solar and storage markets in the Midwest.

- Represent SunPower in state and national trade associations.
- Educate legislators and regulators on the benefits of solar and storage on the electric grid.
- Draft legislation, testimony, and public comments supporting solar and storage markets.
- Advise sales and products teams on opportunities and challenges from a policy perspective.

**Attorney,** Shay Law, Ltd. and Westervelt, Johnson, Nicoll & Keller, LLC, *2016-2022*
Advise and represent national and local renewable energy businesses and associations in their pursuit of strategies to achieve regulatory and legislative goals driving sustainable energy alternatives.

- Educate, advise, and represent clients on various matters related to energy and public utilities, including easement, contract, permitting, municipal ordinance, and utility infrastructure issues.
- Prepare witnesses and testimony in Illinois Commerce Commission tariff, rate, and certificate proceedings.
- Educate legislators and regulators through Illinois General Assembly committee testimony and one-on-one meetings.
- Draft legislation and rules to further client objectives and prepare written advocacy fact sheets, briefing papers, memoranda, media releases, and persuasive presentations.
- Consistently monitor utility filings, state legislative action, trade press, and other sources for issues of interest to or potentially impacting clients.
- Convene and collaborate with diverse groups and individuals to support clients in achieving shared goals.

**Contract Real Estate Developer,** IPS Solar*, 2018-2019 (part-time)*
Work independently to secure sites for and support growth of community solar in Illinois.

- Research suitable sites for solar farms taking into consideration utility service area, proximity of electrical grid and available capacity, topography, and flood plain.

**JOHN D. ALBERS** Williamsville, Illinois
LinkedIn: johnalbersil jalbers532@gmail.com / 217-415-6917

- Negotiate lease terms and compensation with landowners.
- Educate local authorities and area residents about solar energy and community solar projects.
- Work with local government authorities to obtain necessary permits for projects.

**Assistant State's Attorney,** Sangamon County State's Attorney, *2018-2019 (part-time)*
Work as the only attorney in a fast-paced short-notice setting to represent the State of Illinois in mental health cases filed in Sangamon County to aid those afflicted with mental illness. Upon being informed of which cases are going to trial, review files, interview physicians, caregivers, family, and law enforcement, prepare witnesses, and prepare arguments for trial scheduled the next day.

**Administrative Law Judge III, IV, and V,** Illinois Commerce Commission, *1998-2015*
Manage entire trial processes and prepare written decisions related to the electric, natural gas, water, sewer, and telecommunications industries. Based on reputation for being thorough, reliable, impartial, and adept at learning and analyzing new material, advanced quickly to highest ALJ rank. Because of my deep understanding of ICC operations, was recognized within agency as a leader and entrusted with tasks outside typical ALJ duties including leading stakeholder workshops to develop alternative dispute resolution rules and training and mentoring new ALJs on policies, practices, and precedent.

- Rule on and develop policy related to cost recovery, rate design, and service terms and conditions in utility rate cases, tariff proceedings, rulemakings, and other dockets.
- Prepare written decisions summarizing, analyzing, and resolving complex contested issues involving the electric, natural gas, water, sewer, and telecommunications industries, such as the "least cost" location for utility facilities and the use of eminent domain for such.
- Review pending legislation impacting the agency, recommend revisions and agency position, and provide testimony before Illinois General Assembly committees as needed.
- Manage multiple simultaneous complex cases and projects, many with expedited schedules, such as Ameren's petition seeking approval and location of a $1.1 billion 375-mile electric transmission line impacting over 8,400 landowners with a 7½-month deadline.
- Lead multiple hearings in Illinois communities explaining the agency process and facilitating public involvement in matters pending before the agency.

## EDUCATION

**University of Illinois College of Law**, Champaign, IL
*Juris Doctor, cum laude*

**Illinois State University**, Normal, IL
*Bachelor of Arts in Political Science, summa cum laude, Spanish Minor*

**Question:**

14. At page 85 of his direct testimony, witness McPhail states, "The Company will be conducting industry benchmarking and learning sessions with key stakeholders to advance the development of a business case and optimal deployment strategy that supports a reliable and affordable electric distribution system for customers."

a. Please indicate when the Company plans to begin the benchmarking and learning sessions.

b. Please indicate how key stakeholders will be identified and informed of the benchmarking and learning sessions.

c. If known, please identify the key stakeholders.

d. Please describe how the benchmarking and learning sessions will be conducted (i.e., in person, virtually, whether written input will be accepted, the number of sessions, and any other information informing the nature of the sessions).

**Response:**

a. The Company is participating in the workgroup that the Commission directed the Staff to convene to discuss broader DER-related issues. In addition, the Company has already begun, and will continue, to participate in industry benchmarking and learning sessions. These industry sessions collaborate with domestic and international utilities and research organizations on topics related to DER Optimization. These include but are not limited to the Electric Power Research Institute ("EPRI"), Utility Communications Architecture ("UCA"), Institute of Electrical and Electronics Engineers ("IEEE"), and Smart Electric Power Alliance ("SEPA").
b. The Company plans to continue leveraging the MPSC working group to engage key stakeholders within the state of Michigan.
c. The key stakeholders are those engaged in the working group described by the MPSC in Case No. U-21389. If additional opportunities to collaborate with other key stakeholders exist, the Company is willing to participate.
d. Benchmarking sessions are coordinated by organizations listed in part a. The working group is coordinated by the Michigan Public Service Commission.

**Witness:** Scott A. Mcphail
**Date:** July 17, 2024

**Question:**

2. Regarding the Company's DER Optimization Initiative described by witness McPhail starting on page 84, how will the Company have looked at alternative ownership, including third-party models for DER management systems ("DERMS") standardized operational processes?

a. If so, which models?
b. If not, why not?

**Response:**

The Company has not looked at alternative ownership or third-party operation of a DER management system.

a. N/A

b. The Company strives to operate the distribution system in a manner that is safe, reliable, stable, efficient, secure, and affordable. The Company's future ownership and operation of a DERMS is critical to ensuring that these criteria are met. Regardless of the standardized operational processes utilized by third-parties, DERMS must be operated from within the utility's control center, by the utility's grid operators with full visibility into other critical utility owned and operated systems. Accordingly, the Company does not consider third-party ownership or operation of DERMS to be an acceptable alternative.

**Witness:** Scott A. Mcphail
**Date:** August 20, 2024

**Question:**

1. Please refer to the Direct Testimony of witness McPhail regarding the Company's DER Optimization Initiative at page 86, lines 14 and 15.Witness McPhail states, "The Company is projecting DER Optimization capital expenditures of $0 in the bridge period, and $6,633,000 in the test year." What does the Company expect to use the $6,633,000 worth of capital expenditures for in the test year?

**Response:**

The DER Optimization spending is to purchase and implement a variety of hardware and software related products that establish a foundation on which to build the DERMS capabilities. Investments are expected to include a small number of DER Gateway deployments at the grid-edge, as well as basic DER Management System capabilities within the control center.

**Witness:** Scott A. Mcphail
**Date:** September 9, 2024

**Question:**

6. Regarding the Company's DERM proposals described by witness McPhail, please describe how they differ from the one put forth by the Company. Please identify and describe what the Company believes to be the substantive differences between the pending DERMS proposal and the DERMS proposal at issue in each of the following prior dockets that justify approval of the pending proposal: Case Nos. U-20697, U-20963, U-21224, and U-21389? Please be sure to explicitly address any differences the Company deems significant related to cost, ownership of DERMS assets, benefits to ratepayers, operation and control of DERs, proposal rollout schedule, and benchmarks for program evaluation.

**Response:**

Please refer to page 45, lines 1 through 4, of Company witness Kelly's testimony. The primary difference from the prior cited cases is that Michigan's 2023 clean energy law raised the statutory distributed generation cap from 1% of utility peak load to 10%. In prior cases, intervening parties argued that DER penetration was too low on the Company's system to justify investment in a DER management system, and that the 1% cap on the Distributed Generation program would delay the need for DERMS. Given the increase in the Distributed Generation program that has been enabled by the statutory change in Michigan, the Company will need DER Optimization to ensure it can manage that higher level of distributed generation on its grid and needs to begin that investment in the near term rather than waiting for that full 10% to manifest itself.

**Witness:** Scott A. Mcphail
**Date:** August 23, 2024

**Question:**

13. To the extent that the Company plans to control DERs not owned by the Company, please identify the compensation structure under which the owners of the DERs will receive compensation for allowing the Company to control each owner's DER(s).

**Response:**

Consumers Energy has not identified a compensation structure at this time. In the Commission's March 1, 2024 Order in Case No. U-21389, pg. 43, the Commission noted that Staff has been directed to convene a workgroup to consider certain broader DER-related issues. The Company has been participating in the corresponding Demand Response Aggregation Workgroup, which may make progress toward addressing this question in line with the Commission's direction.

**Witness:** Scott A. Mcphail
**Date:** July 17, 2024

**Question:**

5. Starting on page 84 of his direct testimony, witness McPhail describes the Company's DER Optimization Initiative.

a. What other states, jurisdictions, programs, policies, or practices has the Company studied for this rate case?

b. After studying them for this rate case, what did the Company learn from these other states, jurisdictions, programs, policies, or practices?

c. Why did the Company choose to study these other states, jurisdictions, programs, policies, or practices for this rate case?

**Response:**

a. The Company did not study specific practices in other jurisdictions as part of the development of this rate case. Through involvement with EPRI and other industry forums, the Company is maintaining awareness of various practices throughout the United States and other countries, but recognizes that the approach must be specifically tailored to the state where the DER Optimization solutions will be deployed. The industry benchmarking sessions referenced in response to U21585-MEIU-CE-0083 part a, continue to review how other states have approached this topic. Additionally, the Company is supportive of the established work group formed by the MPSC as discussed in Case No. U-21389.

b. As discussed in my testimony, page 85, lines 9-17, the Company is still in the process of exploring strategies to support DER optimization.

c. Please see responses to a and b above.

**Witness:** Scott A. Mcphail
**Date:** August 20, 2024

**Question:**

15. At page 85 of his direct testimony, witness McPhail states, "Utilizing these findings, the Company will collaborate with an industry-leading consultant to formalize a business case and deployment strategy consisting of the implementation of a variety of hardware and software deployment projects that result in improved grid-edge visibility, ensuring a safe, reliable electric distribution system for customers and alignment with Federal Energy Regulatory Commission ("FERC") Order 2222 and the 2023 Michigan clean energy law."

a. If known, please identify the industry-leading consultant.

b. If the consultant has not been selected, please identify the criteria that will be used to select the industry-leading consultant.

c. If the consultant has been selected, please identify the experience with DERMS that the consultant possesses.

d. If the consultant has not been selected, please identify the minimum level of experience with DERMS that the consultant must possess in order to be eligible for selection.

**Response:**

a. The industry-leading consultant has not been selected. Upon approval of DER Optimization funding in the rate case, the Company will initiate the Request for Information (RFI)/Request for Proposal (RFP) process to identify and select a consultant.
b. Consultants will be scored based on a number of categories, including, but not limited to:
   - Price,
   - Technical Evaluation, and
   - Qualifications/Experience.

   Following the RFI/RFP meetings with consultants, scores will be reviewed to determine which consultant will be selected.

c. N/A
d. A minimum level of experience with DERMS has not been evaluated and will not be the sole determining factor of which consultant is selected. The Company will select the consultant based on the aggregate score across all categories discussed in part b.

**Witness:** Scott A. Mcphail
**Date:** July 17, 2024

**STATE OF MICHIGAN**
**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

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|---|---|---|
| In the matter of the application of **Consumers Energy Company** for authority to increase its rates for the generation and distribution of electricity and for other relief. | ) ) ) ) ) ) | **Case No. U-21585** |

## PROOF OF SERVICE

STATE OF SOUTH CAROLINA )
) ss.
COUNTY OF BERKELEY )

Summer R. Dukes, the undersigned, being first duly sworn, deposes and says that she is a Paralegal at Potomac Law Group PLLC and that on the 27th day of September, 2024 she served a copy of the Direct Testimony of Dr. Laura S. Sherman; Direct Testimony of John D. Albers; Direct Exhibit List; Exhibits of Dr. Laura S. Sherman; and Exhibits of John D. Albers on behalf of the Michigan Energy Innovation Business Council, The Institute for Energy Innovation, and Advanced Energy United, upon those individuals listed on the attached Service List via email.

Summer Dukes
Digitally signed by Summer Dukes
Date: 2024.09.27 11:26:12 -04'00'

Summer R. Dukes

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