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July 26, 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-21534**

Dear Ms. Felice:

Attached for electronic filing in the above-referenced matter, please find the Public Redacted Direct Testimony of Dr. Laura S. Sherman and Direct Testimony of Justin R. Barnes on behalf of Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Advanced Energy United. Thank you for your assistance in this matter.

Very truly yours,
Justin K. Ooms
Digitally signed by Justin K. Ooms
Date: 2024.07.26 16:48:08 -04'00'
Justin K. Ooms

TL/kd
Enclosure
c. All parties of record.

STATE OF MICHIGAN

MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	)))))))	**Case No. U-21534**

PUBLIC REDACTED

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"] general electric rate case);
- U-20165 (Consumers Energy Integrated Resource Plan case);
- U-20162 (DTE Electric Company ["DTE Electric," "DTE" or the "Company"] 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); and
- U-21389 (Consumers Energy general electric rate 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);

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 based on my experiences as the President of Michigan EIBC and IEI. My direct testimony also addresses issues related to the Company's Commercial and Industrial ("C&I") battery energy storage pilots.

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): 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
- Exhibit MEIU-3 (LSS-3): California Public Utilities Commission, Decision 22-11-040, "Decision on Transportation Electrification Policy and Investment," November 21, 2022
- Exhibit MEIU-4 (LSS-4): 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

- Exhibit MEIU-5 (LSS-5): Georgia Public Service Commission, Docket No. 44280, "Order Adopting Settlement Agreement as Modified," December 30, 2022

- Exhibit MEIU-6 (LSS-6): 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

- Exhibit MEIU-7 (LSS-7): Massachusetts Department of Public Utilities, Docket 17-05, "Order Establishing Eversource's Revenue Requirement," November 30, 2017

- Exhibit MEIU-8 (LSS-8): 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

- Exhibit MEIU-9 (LSS-9): 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

- Exhibit MEIU-10 (LSS-10): 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

- Exhibit MEIU-11 (LSS-11): Minnesota Public Utilities Commission, Docket 18-643, "Order Approving Pilots with Modifications, Authorizing Deferred Accounting, and Setting reporting Requirements," July 17, 2019

- Exhibit MEIU-12 (LSS-12): Missouri Public Service Commission, Docket 2018-0132, "Order Approving Second Stipulation and Agreement," February 6, 2019

- Exhibit MEIU-13 (LSS-13): 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

- Exhibit MEIU-14 (LSS-14): New York Public Service Commission, Case 18-E-0138, "Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs," July 16, 2020

- Exhibit MEIU-15 (LSS-15): Pennsylvania Public Utilities Commission, Docket No. R-2018-3000124, "Opinion and Order," December 20, 2018
- Exhibit MEIU-16 (LSS-16): 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
- Exhibit MEIU-17 (LSS-17): 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
- Exhibit MEIU-18 (LSS-18): Public Attachment "U-21534 MEIUDE-1.4 EV Sales Forecast"
- Confidential Exhibit MEIU-19 (LSS-19): Confidential Attachment "NDA U-21534_MEIUDE-1.4_DTE EV Charging market model v.40"
- Exhibit MEIU-20 (LSS-20): Discovery Response MEIUDE-2.1a
- Exhibit MEIU-21 (LSS-21): Discovery Response MEIUDE-2.4a

II. <u>TRANSPORTATION ELECTRIFICATION</u>

A. OVERVIEW OF DTE'S TRANSPORTATION ELECTRIFICATION PLAN

Q. Please summarize your view of DTE's transportation electrification proposals in this case.

A. DTE's proposals regarding transportation electrification are presented primarily in the testimony of Pina Bennett.[1] The Company describes the status of the existing Charging Forward program elements and then details its three-year Transportation Electrification Plan (2025–2028, "TEP"). The Charging Forward program consists of three permanent

[1] Direct Testimony of Pina Bennett on behalf of DTE Electric Company ("Bennett Direct"), Case No. U-21534.

programs (Education & Outreach, Emerging Technology Fund, and Program Administration) and nine pilot programs (Home Charger Rebates, Home Charger Installation, EV Rebates, Business Charger Rebates, Business Charger Installation, eFleet Charger Rebate, eFleet Battery Support, School Bus Chargers and Charging Hubs).[2] Per the Commission's Order in the Company's last rate case (Case No. U-21297), the Company will be ending the Home Charger Installation pilot and transitioning it to a value-added program and service ("VAPS").[3]

The majority of witness Bennett's testimony is dedicated to a detailed description of the Company's TEP, including its benefit-cost analysis ("BCA"). The Company developed the TEP over a 15-month period, during which DTE gathered stakeholder input (including from MEIU) and benchmarked the TEP against utility TEPs from Commonwealth Edison ("ComEd"), Consolidated Edison ("ConEd"), National Grid Massachusetts ("National Grid"), Southern California Edison ("SCE"), Xcel Colorado, and Xcel Minnesota.[4]

Q. According to DTE, what trends emerged from the benchmarking against these TEPs?

A. According to witness Bennett, the Company observed several key themes in these other utility TEPs including:

> 1. Most of the TEPs outline investment and programs for a three- to five-year timeframe, which is longer than a typical general rate case bridge and test period,

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[2] *Id.,* p. 5.

[3] *Id.,* p. 10.

[4] *Id.,* p. 16.

> 2. The TEPs can accommodate programmatic changes, as needed, in a dynamic environment,
> 3. The TEPs generally emphasized Level 2 charging over DCFC to improve overall customer affordability, due to the higher number of use cases for Level 2 charging, lower costs of installing Level 2 chargers compared to DCFCs, and minimized grid impact, and
> 4. The TEPs often include an emphasis on compliance with statewide regulations, equity, multi-unit dwelling and fleet segments, supporting functions, and managing incremental EV load, as well as a trend towards make-ready incentives as opposed to utility ownership, discussed in more detail below.[5]

Q. What specifically did DTE find about make-ready programs from the Company's review of other utility TEPs?

A. According to witness Bennett, "[make-ready] infrastructure programs are the most commonly offered type of incentive program in the TEPs."[6] Witness Bennett goes on to cite a study from the Midcontinent Transportation Electrification Collaborative that found that in utility TEP filings from 2012 through Q3 2022, "nearly $2 billion had been allocated for make-ready infrastructure programs, whereas in that same period, less than $1 billion had been allocated for utility own-and-operate programs."[7]

Q. What is "make-ready infrastructure"?

A. "Make-ready infrastructure" refers to the electrical equipment necessary to serve the load from a charging station. This can include sub-panels, main-panels, conductors, wiring, transformers, and other equipment that is located on the utility side of the customer's meter

[5] *Id.,* pp. 17-18.

[6] *Id.,* p. 20.

[7] *Id.,* p. 21.

between the customer's meter and the EV charging station as well as the utility electric infrastructure needed to connect and serve a new EV charging station. Through make-ready programs, utilities might, for instance, invest in rate-based distribution upgrades, branch line extensions, and conductors/panels, while leaving investments in chargers, charger ownership, operation and maintenance, marketing, customer service, and network operation to site hosts and experienced private sector providers.

Q. What are the benefits of make-ready programs?

A. Make-ready programs have become common among utilities across the country with programs approved in states including California,[8] Connecticut,[9] Georgia,[10] Illinois,[11] Massachusetts,[12] Minnesota,[13] Missouri,[14] New Mexico,[15] New York,[16] Pennsylvania,[17] Rhode Island,[18] and Virginia.[19] A make-ready program provides a reasonable balance

[8] See Exhibits MEIU-2 (LSS-2) & MEIU-3 (LSS-3).

[9] See Exhibit MEIU-4 (LSS-4).

[10] See Exhibit MEIU-5 (LSS-5).

[11] See Exhibit MEIU-6 (LSS-6).

[12] See Exhibits MEIU-7 (LSS-7), MEIU-8 (LSS-8), MEIU 9 (LSS-9) & MEIU-10 (LSS-10).

[13] See Exhibit MEIU-11 (LSS-11).

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

[15] See Exhibit MEIU-13 (LSS-13).

[16] See Exhibit MEIU-14 (LSS-14).

[17] See Exhibit MEIU-15 (LSS-15).

[18] See Exhibit MEIU-16 (LSS-16).

[19] See Exhibit MEIU-17 (LSS-17).

between accelerating EV adoption, returning some net revenue from EV charging to those customers, and retaining substantial net revenue for the benefit of non-EV customers.

Q. How are make-ready programs different from policies that waive utility Contribution in Aid of Construction requirements for EV charging stations?

A. Make-ready programs are related to, but different from, policies that waive utility Contribution in Aid of Construction ("CIAC") obligations. CIAC obligations represent the portion of the costs for electric infrastructure upgrades that are necessary to support a new load which are borne by the customer interconnecting that new load. These CIAC costs are typically limited to the amount of marginal revenue not expected to be recovered by the new load. In other words, a customer only has to cover costs up to the amount that they will not be contributing over time through the new electricity purchases they will make.

As a matter of policy, many utilities waive CIAC obligations for public EV charging infrastructure[20, 21] because, as discussed further below, the benefits to ratepayers from that public EV charging infrastructure far exceed the revenue generated at an individual charging station site. However, a simple waiver of CIAC obligations does not necessarily cover the full suite of costs that a customer might incur to install new public EV charging infrastructure. For example, as shown in witness Bennett's testimony, for installation of a public on-route direct current fast charger ("DCFC"), the average cost of the utility make-

[20] New Jersey A2360/S3285 P.L. 2021, c.441 requires electric public utility to charge residential rate for service used by residential customer for electric vehicle charging at charging stations within certain designated parking spaces, N.J. REV. STAT. § 48:7-6.1, available at https://pub.njleg.state.nj.us/Bills/2020/PL21/441_.PDF.

[21] CALIFORNIA PUBLIC UTILITIES CODE § 740.19.

ready infrastructure is $20,630 (including the customer CIAC) and the average cost of the customer make-ready infrastructure is $61,890.[22] This means that a waiver of a customer's CIAC obligations would amount to approximately 15 percent of $20,630, or $3,094.50, whereas a make-ready program could cover those CIAC costs and all or a portion of the customer's (much larger) make-ready infrastructure costs.

Q. From your review of utility TEPs, what other elements are essential?

A. I reviewed the six TEPs cited by the Company: ComEd (2022),[23] ConEd (2020),[24] National Grid (2021),[25] SCE (2020),[26] Xcel Colorado (2021),[27] and Xcel Minnesota (2022).[28] I also reviewed Ameren Illinois' ("Ameren") 2022 TEP,[29] which was not cited by the Company.

[22] Bennett Direct, p. 30.

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

[24] 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.

[25] 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.

[26] 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.

[27] 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.

[28] 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.

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

In addition to the commonalities noted by the Company, several of these TEPs include a robust benefit-cost analysis ("BCA"). 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.[30, 31, 32] Of the TEPs that I reviewed, ComEd,[33] Xcel Colorado,[34] Xcel Minnesota,[35] and Ameren[36] all included a BCA. In addition, while it did not conduct its own BCA, National Grid[37] utilized evidence

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[30] 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.

[31] *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.

[32] 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.

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

[34] 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=.

[35] 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.

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

[37] 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.

from a BCA conducted by the New York Public Service Commission Staff[38] as the basis for evaluation of its proposed public and workplace make-ready programs.[39]

Several states including Colorado,[40] Illinois,[41] and Minnesota[42, 43] 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).[44] After this initial forecast, BCAs may include as benefits estimated revenue from charging, expected state and federal incentives, any customer contributions under 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

[38] 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.

[39] 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.

[40] 2019 Colo. Sess. Laws 3433–3437, available at https://leg.colorado.gov/sites/default/files/documents/2019A/bills/sl/2019a_sl_383.pdf.

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

[42] 2023 Minnesota Statutes § 216B.1614, available at https://www.revisor.mn.gov/statutes/cite/216B.1614.

[43] 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.

[44] 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.

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.

B. TEP BCA

Q. Did the Company conduct a BCA?

A. Yes, but it was limited in scope. DTE Electric's BCA included several of the elements described above but, as described further below, limited the benefits considered to only two: increased revenue and impact on ratepayers. Specifically, according to witness Bennett, the Company "used the net present value ("NPV") of the revenue requirement assessed for the TEP programs as the BCA test for the TEP."[45]

Q. In the BCA, how does DTE predict that EV sales will grow in the Company's service territory?

A. According to witness Bennett, there are 46,000 EVs registered in DTE Electric's service territory and the Company "forecasts this number increasing to an estimated 326,000, including [medium- and heavy-duty vehicles] by 2028."[46] The Company created this forecast using both actual EV registration data from 2019 to 2022 and long-term forecasts from industry experts. The Company applied a lower growth rate in the near term than

[45] Bennett Direct, p. 53.

[46] *Id.*, p. 22.

these national forecasts to account for the fact that EV deployment is currently more rapid in states with Zero Emission Vehicle ("ZEV") mandates.[47]

Q. Do you agree with the EV deployment rate predicted by the Company?

A. In response to a discovery request, the Company provided a spreadsheet of the EV sales forecast data graphed in witness Bennett's Figure 1 (Exhibit MEIU-18 (LSS-18)). That spreadsheet shows that the Company based its forecast on a down-scaled average of a number of independent national forecasts. This is procedurally reasonable but on examination, two of the six forecasts utilized projected national EV sales that are too low to be compatible with recently adopted Federal vehicle emission standards, which the U.S. Environmental Protection Agency ("EPA") characterized as based on EVs being 30 to 56 percent of light duty vehicle sales by 2032.[48] It is therefore likely that the Company's EV sales forecast is low.

Q. How did DTE calculate the approximate number and mix of chargers required to serve these vehicles?

The Company's calculations of the approximate number and mix of chargers required to serve the vehicles it forecasts is contained in a confidential workpaper provided in response to a discovery request (Confidential Exhibit MEIU-19 (LSS-19)). Aside from the likelihood that the underlying EV sales forecast, and hence the EV deployment forecast, is

[47] *Id.*, p. 24.

[48] U.S. Environmental Protection Agency, "Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles: Final Rule," March 2024, available at https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1019VP5.pdf.

low, the methods the Company used to calculate the number and mix of chargers were not unreasonable. Naturally, there were a significant number of assumptions included in these calculations that could prove to be wrong, but I recommend the Commission accept those forecasts for the purpose of considerations in this case. Revisions will be necessary in future cases and should serve to track the evolving market, assuming that the Company continues to update its model.

Q. What is the biggest driver of the investment needed to install these chargers?

A. According to witness Bennett,

> Even though the public charging segment represents just 3% of the chargers needed, as shown in the figure above, it is the largest driver of investment required in the near term at nearly 40% due to the high costs of DCFCs and the associated installation. Conversely, although the single-family home charging segment. represents over 80% of the total projected chargers, they only require about 25% of the total investment since they are much less expensive.[49]

Q. Are there additional benefits from the installation of DCFCs?

Yes. Although, as the Company notes, public DCFCs are more expensive than Level 2 public or residential chargers, it has been well documented that range anxiety is a primary

[49] *Id.,* p. 29.

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 vehicle and charging station

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[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.

availability.[62] In fact, during DTE's stakeholder process to develop the TEP, the Company found that

> Stakeholders ranked all the public charging subsegments, including on-route and destination charging, as the most important for utility action because the availability of public charging is critical to reducing range anxiety, which is a key barrier to EV adoption. Reliable, on-route fast charging, defined as fast charging within one mile of a major throughway exit, can increase customer's confidence in the refueling infrastructure . . .[63]

Additionally, realizing the benefits from greenhouse gas and criteria pollutant emissions reductions requires more robust and widespread public charging infrastructure. According to Xcel Colorado,

> an increase of about 15 percent in the number of personal and commercial electric LDVs on the road as a result of the public charging investments helps produce this increase in net benefits for drivers and for society.[64]

Given that a large portion of EV charging occurs at home, a significant portion of the Company's revenue projections from EV charging also come from home charging. The Company's confidential EV market model, provided in response to discovery request in this case (Confidential Exhibit MEIU-19 (LSS-19)) includes estimated electricity sales for EV charging. That model shows that the Company expects at-home charging to provide approximately [redacted] of projected kWh sales

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[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] Bennett Direct, p. 46.

[64] Xcel Colorado, "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. p. 28.

and approximately [redacted] of projected EV charging revenue to the Company. However, because sufficient build-out of public charging necessarily precedes increased EV adoption, those expected benefits to revenues (and decreased pressure on rates for all ratepayers) will not be realized without sufficient investments in public charging infrastructure.

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

A. Yes, I have three primary concerns. First, the Company's BCA is overly conservative in a number of its assumptions. Second, the Company's BCA incorrectly assumes a constant utilization rate over time for all types of chargers. Finally, the Company's BCA fails to account for any of the societal benefits realized as a result of transportation electrification.

Q. Please explain your first concern, about the BCA's overly conservative assumptions.

A. According to witness Bennett,

> It is important to note that the BCA only considers incremental load from rebated chargers (i.e., "qualified" additional EV load). The "qualified" additional EV load occurring on TEP-supported chargers – and accounted for in the BCA – is only about 10% of the total expected EV load through 2030.[65]

Witness Bennett goes on to state that

> The BCA only considers incremental load from rebated chargers; it does not take credit for any "network effects" of EV sales influenced by the TEP through reduced range anxiety.[66]

[65] Bennett Direct, p. 54.

[66] *Id.*, p. 58.

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 million more than their associated costs in each of Illinois[67] and Virginia,[68] $26.7 million more in Colorado,[69] and $85.3 million more in New Jersey.[70] In Colorado[71] and New Jersey,[72] 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.

By only accounting for load from chargers that receive a rebate, the Company estimates that it is ignoring 90 percent of the actual increase in expected revenue from EV charging through 2030. This means that, all else being equal, the revenue estimated in the Company's BCA is 90 percent lower than it actually will be. Effectively, the Company is

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[67] 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.

[68] 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.

[69] 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.

[70] 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

[71] 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.

[72] 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

ignoring the by now well-proven fact that the existence of public EV charging stations directly enables customers to purchase EVs,[73, 74, 75, 76] leading to significant at-home charging and revenue from electricity sales. [77, 78, 79, 80, 81] Not only does this accounting decision decrease the estimated benefits of EV investments, but also, by artificially deflating the benefits of these programs, it may unreasonably limit the revenue available for rebates and other TEP programs. The relative percentage of total revenue used to decrease rates for all ratepayers versus revenue used for investments in TEP programs is a policy decision that should be determined by the Company, the Commission, and

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[73] 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/.

[74] 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.

[75] 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.

[76] 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.

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

[78] 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.

[79] 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.

[80] 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.

[81] 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.

stakeholders. However, to make this important policy decision, it is necessary to start with an accurate accounting of the total amount of incremental revenue expected to be generated by EV charging. As such, the Company must first account (as accurately as possible) for 100 percent (not 10 percent) of the additional revenue generated by EV charging in its service territory. The current policy debate, in part because it is based on an assumed total revenue that represents only 10 percent of the total additional expected revenue, serves to unreasonably limit the size and scope of TEP programs.

Q. Please elaborate on your second concern, with respect to the utilization rate assumption.

A. The Company's BCA assumes a constant utilization rate over time for all types of chargers. This might be reasonable for at-home chargers where the number of vehicles using the charger is not expected (in most cases) to increase. However, this is unreasonable for public DCFC or Level 2 chargers. According to experts, public and workplace charging in the United States will need to grow by over 1000 percent - from 216,000 to 2.4 million - between 2020 and 2030, which will require $28 billion in investment.[82, 83] In 2016, there were seven EVs to each public charging port in the United States. By 2023, given growth

[82] 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.

[83] 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.

in EV adoption, there were more than 20 EVs per public charging port.[84, 85] Failure to account for this increased utilization related to increased EV adoption diminishes the estimated benefits of public charging infrastructure by ignoring significant actual additional revenue at each charging port.

Q. Please explain your third concern about the Company's BCA, regarding societal benefits.

A. The Company's BCA fails to account for any of the societal benefits realized as a result of transportation electrification. These societal benefits include 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.[86, 87, 88, 89, 90]

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84 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/.

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

86 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.

87 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.

88 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.

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

90 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,[91] including reduced greenhouse gas emissions and reduced criteria pollutant emissions,[92] can be accurately quantified. Among the TEPs that I reviewed, ComEd,[93] Xcel Minnesota,[94] Xcel Colorado,[95] and Ameren[96] 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.

[91] 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.

[92] 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.

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

[94] 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.

[95] 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=.

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

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.[97] Following a court ruling in 2008, the SCC has also been incorporated into these Federal agency benefit-cost analyses.[98] To ensure accuracy and consistency across agencies, in 2009, the IWG was established and the first SCC estimates were published in 2010.[99] In 2016, the IWG published estimates of the social costs of two additional greenhouse gases: methane and nitrous oxide.[100] 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.[101] There are several important

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

[98] 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.

[99] 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.

[100] *Ibid.*

[101] *Ibid.*

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 current impacts, whereas a low discount rate suggests that future impacts are equally significant to current impacts.[102] 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%].[103]

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. [104, 105] 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,

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

[103] 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.

[104] 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.

[105] 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[106, 107, 108] and public utility commissions[109, 110, 111, 112] 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.[113]

Also in 2018, the Minnesota Public Utilities Commission ("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

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

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

[108] 2019 Colo. Sess. Laws 3290, available at https://leg.colorado.gov/sites/default/files/documents/2019A/bills/sl/2019a_sl_359.pdf.

[109] 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.

[110] 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.

[111] 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.

[112] 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%2020180802.pdf/575a6d2b-ad09-d8f8-e566-39a0c04f9a43.

[113] 220 ILCS 3855/1-75(d-5)(1)(B)(i).

options.[114] To do this, the PUC conducted integrated assessment models consistent with those used by the IWG. The 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.[115] Overall, the 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 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.[116]

[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.

[115] *Ibid.*

[116] 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,[117] Xcel Minnesota,[118] Xcel Colorado,[119] and Ameren[120] 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,[121] 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.[122] 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

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

[118] 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.

[119] 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=.

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

[121] 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.

[122] 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.[123] 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. [124, 125] 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.[126]

In another example, Xcel Minnesota[127] and Xcel Colorado[128] 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.[129] In accordance with the Minnesota

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[123] 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.

[124] *Ibid.*

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

[126] 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.

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

[128] 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=.

[129] 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

PUC order,[130, 131] 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).[132] Xcel Colorado, in accordance with SB 19-236,[133, 134] converted avoided emissions to costs based on assumption of $46 per metric ton of carbon.[135]

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:[136]

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

[130] 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.

[131] 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.

[132] 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.

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

[134] 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.

[135] 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=.

[136] 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.

- *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 programs' financial impact on ratepayers and the utility system but also the broader benefits that accrue to society as a whole. These societal 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[137] and Ameren,[138] or by using an SCT. Utilities can also utilize more than one of these cost tests to evaluate the associated

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

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

costs and benefits of their proposed programs, with one typically identified as the primary test for decision-making.[139, 140] 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).[141] Similarly, Xcel Minnesota[142] and Xcel Colorado[143] also performed RIM tests, but supplemented these tests with a PCT to assess the costs and 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. How does DTE Electric's BCA utilize these cost tests?

A. The Company's analysis, which it presents as a BCA, is approximately a RIM test in that it calculates the net of a portion of the Company's revenues from EV charging electricity

[139] 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.

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

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

[142] 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.

[143] 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=.

sales that the Company attributes to the TEP programs and costs of the TEP. In contrast, the National Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources[144] recommends consideration of utility system impact along the lines done by the Company in this case (see Manual Table 10-1) but also includes non-electric energy system impacts (see Manual Table 10-2) that would in this case principally be the avoided cost of transportation fuel supply and societal impacts (see Manual Table 10-4) including reduced greenhouse gas and criteria pollutant emissions, as described above, as well as other environmental effects, public health impacts, and economic benefits. The Company has considered none of these other benefits, having not conducted a TRC or SCT.

The net effect of failure to consider substantial benefit categories in the BCA is to undervalue and therefore discourage investments that would be beneficial. As long as the incremental total benefits of investments in transportation electrification exceed the incremental costs of transportation electrification, society is better off by increasing spending on transportation electrification in order to gain those incremental benefits.

Q. In light of the three concerns you explain above, what do you recommend with respect to the Company's BCA?

A. First, I recommend that the Company account in its BCA for all of the increase in expected revenue from increased EV charging through 2030 in its TEP (i.e., instead of 10 percent of the expected revenue). The Company's current accounting is unreasonably conservative

[144] National Energy Screening Project, "National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources," August 2020, available at https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/.

and likely limits the scope of the EV charging programs. A full accounting of expected revenues should then allow an increase in the size of the TEP programs designed to ensure manifestation of the expected benefits by increasing access to public EV charging options.

Second, I recommend that the Company include in its BCA an increasing utilization rate over time for public chargers. It is clear that utilization rates for public chargers have been increasing significantly in recent years as EV adoption increases. Failure to account for this increased utilization diminishes the benefits of public charging infrastructure by ignoring significant actual additional revenue at each charging port.

Finally, I recommend that the Company consider additional benefits in its BCA including societal benefits such as, greenhouse gas and criteria pollutant emission reductions. This could be done through the utilization of multiple cost tests.

C. PROPOSED EV CHARGER REBATE PROGRAMS

Q. Turning to the proposed rebate programs, what does DTE propose with respect to TEP rebate programs?

Witness Bennett summarizes the Company's proposed TEP rebate programs in Table 9 of her direct testimony.[145] Rebates of differing amounts are proposed for LI single-family homes ("SFH"), LI and non-LI multi-unit dwellings ("MUD"), public DCFC in rural or disadvantaged communities and other on-route public DCFC, and fleet chargers, including

[145] Bennett Direct, p. 38.

both transit and school bus fleets and other fleets. The total cost of these proposed rebate programs over the TEP period (2025-2028) is expected to be $124.8 million.

Q. Do you support these rebate proposals?

A. In general, I am supportive of the Company's continued use of rebates to support build-out of private and public EV charging infrastructure. However, as described below, I have some specific concerns with the requirements for some of the proposed rebate categories. In addition, I have concerns regarding the Company's proposal to begin requiring CIAC for infrastructure costs to enable the installation of public EV charging infrastructure and lack of any proposed make-ready infrastructure program.

Q. What does the Company propose in terms of SFH rebates?

A. The Company proposes to spend $24 million to support installation of home chargers at LI households. These rebates would cover the full cost of the Level 2 charger (up to $2,200) plus the full cost of the installation.[146] These rebates would be available to LI households with an income of up to 200 percent of the federal poverty limit (approximately $60,000 for a four-person household) as well as proof of an EV purchase or lease, installation of an ENERGY-STAR certified EV charger, and enrollment in a Time-of-Use ("TOU") rate.[147] The Company does not propose to continue its home charger rebates for customers at higher income levels.

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[146] *Id.*, p. 40.

[147] *Id.*, pp. 41-42.

Q. Are you concerned with this proposal?

A. In general, I am supportive of the provision of home charger rebates, especially to LI households, which are likely less able to afford the costs associated with a charger and the necessary upgrades to enable one. However, I am concerned that the requirements set by the Company may be too restrictive and not sufficiently support deployment of chargers. For example, as the Company notes,

> It will be critical to monitor and adjust the income eligibility threshold based on market dynamics of EV adoption. For example, if the upfront premium for EVs continues to remain out of reach for low-income customers, DTE Electric may need to adjust the income threshold of the Home Charger Rebate program upwards to meaningfully support this segment and encourage EV adoption in Southeast Michigan.[148]

It is important to balance targeting incentives to those who need it most with ease of access and supporting customer participation. Unfortunately, overly restrictive income eligibility requirements could reduce effectiveness of the programs by limiting participation. For example, in New Mexico, in its inaugural TEP, Southwestern Public Service Company ("SPS") set the same income threshold as DTE Electric proposes for LI rebates (i.e., 200 percent of the federal poverty level). With this requirement, SPS did not administer a single LI rebate, though its service territory is 34 percent LI customers.[149] As a result, SPS proposed in April 2024 to expand eligibility for these rebates to all customers living in underserved communities.[150]

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[148] *Id.*, p. 42.

[149] New Mexico Public Regulation Commission, Case No. 24-00120-UT, Direct Testimony of Patrick J. Murphy on behalf of Southwestern Public Service Company, April 1, 2024, available at https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/Direct%20Testimony%20of%20Patrick%20J.%20Murphy.pdf, p. 20.

[150] *Id.,* p. 21.

In DTE Electric's case, it seems likely that, given the restrictive income thresholds proposed for the SFH rebates, the Company may similarly struggle to deploy LI rebates. I recommend that the Company both increase the threshold for LI rebates to 400 percent of the federal poverty level and allow customers to self-attest to their income. This would eliminate any additional paperwork necessary to verify income levels, ensure that LI customers receive the rebates, and also help improve the likeliness of successful deployment of these rebates.

Q. Do you have any other recommendations for the LI SFH rebates proposal?

A. Yes. As an alternative option to increasing the threshold for rebates to 400 percent of the federal poverty level, to ensure meaningful support for LI households through this rebate segment, the Company could modify its eligibility criteria to allow both an income qualification and a location-based qualification. As noted by witness Bennett,

> The most common way in which these utilities are focusing on equity is through enhanced program offerings for commercial customers located in [disadvantaged communities or] DACs (the definition varying by utility and state) and for residential customers that are either located in DACs or that meet an income threshold set by the utility.[151]

Instead of offering SFH rebates to customers only based on income level, the Company could also offer its Home Charger Rebates to customers living in disadvantaged communities ("DAC"). Such an expansion of the LI rebate program would support the Company's assertion in a discovery response that its "rebate program is designed to be

[151] Bennett Direct, p. 19.

inclusive and broad in its impact" (Exhibit MEIU-20 (LSS-20)). This change would also align the Company's TEP with several of the TEPs benchmarked by the Company, including those of ComEd,[152] National Grid,[153] and SCE.[154] Among those TEPs, all equity-based residential rebates are based on whether a customer is LI or living in a DAC, not solely on LI qualifications.

The Company proposes to use the identification of DACs in the Michigan State Plan for EV Infrastructure Development ("State Plan")[155] for its Business Charger Rebates program, as described below. In the State Plan, the Michigan Department of Transportation ("MDOT") identifies DACs using the federal Climate and Economic Justice Screening Tool ("CEJST") and MDOT's Environmental Justice ("EJ") Priority tool.[156] According to witness Bennett in a discovery response (Exhibit MEIU-20 (LSS-20)),

> The Company is committed to supporting all the types of disadvantaged communities identified by the Michigan State Plan for EV Infrastructure Deployment. This includes MDOT EJ Priority, CEJST DAC, and MDOT EJ Priority and CEJST DAC communities. Our rebate program is designed to be inclusive and broad in its impact. Therefore, eligibility for rebates will not be limited to a single type of DAC community. Instead, we propose to determine rebate eligibility based on all three types of DAC communities

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

[153] 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.

[154] 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.

[155] Michigan Department of Transportation, "Michigan State Plan for EV Infrastructure Deployment," 2023, available at https://www.michigan.gov/mdot/-/media/Project/Websites/MDOT/Travel/Mobility/Mobility-Initiatives/NEVI/FY23-MI-Plan-for-EV-Infrastructure-Deployment.pdf?rev=968c7cbcf92c4b2abb08573f2af0f9f5&hash=409ED1B68C1FBEE6E52E334690405162.

[156] *Ibid.*

> identified in Figure 17 of the Michigan State Plan for EV Infrastructure Deployment.

Providing rebates to residents for home chargers according to this same metric would still ensure that rebates are targeted to energy-burdened households[157] but would make implementation of the program more efficient because determinations of annual income can be complicated and time consuming. It would also help to ensure that the program is successful and that rebates are deployed to residents who are most in need of support to be able to access EV chargers at their homes.

Q. What does the Company propose for MUD-based chargers?

A. The Company proposes to provide rebates both for LI MUD housing and for other MUDs. For income-qualified MUDs, the Company proposes to provide rebates that would cover the cost of the Level 2 charger and the full cost of installation (including the CIAC portion). To qualify for these rebates, an MUD must meet one of the following (or an equivalent) criteria: be owned and managed by a public entity, include at least 40 percent of units for residents with household incomes below 60 percent of the area median income, or have at least 40 percent of residents in the Housing Voucher Program.[158] For all other MUDs, the Company proposes to provide a rebate of $5,000 that would only cover the cost of the Level 2 charger. In either case, the Company requires the charger to be networked, requires

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[157] *Id.,* p. 61.

[158] Bennett Direct, p. 44.

a commitment to 97 percent uptime, and requires "demonstrated tenant interest in installing EV chargers."[159]

Q. What is your assessment of this proposal?

A. In general, I am supportive of this proposal. Enabling charging infrastructure at MUDs is important to expanding access to at-home charging and ensuring more equitable access to charging. However, it is important that the requirement that an MUD "demonstrate[] tenant interest" in EV chargers is not unreasonably stringent. As indicated by witness Bennett,

> The average total cost of installation (less utility-owned non-CIAC utility make-ready) is approximately $14,400 over the TEP timeframe, as shown in Table 9, driven primarily by customer make-ready, which often requires trenching and extending electrical wiring to parking areas,[160]

Given this, especially for MUDs that do not meet the Company's LI thresholds, even with the $5,000 charger rebate, there will be significant make-ready costs that the MUD owner will be required to pay. As such, I would presume that any MUD owner who is willing to incur those costs must either hope to attract tenants who will see EV charging as a benefit or hope to retain tenants who wish to have on-site EV charging. Given this, I recommend that the Company ensure that the requirement to demonstrate tenant interest is limited to a self-attestation. If more than a self-attestation is required, the Company could accept information such as a resident survey or survey of potential future residents that indicates interest in EV chargers. It appears that the Company is open to these types of requirements. According to a discovery request in this case (Exhibit MEIU-21 (LSS-21)),

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[159] *Id.,* pp. 44-45.

[160] *Id.*, p. 43.

> To demonstrate tenant interest in installing EV chargers, an MUD could use one or more of the following:
> - tenant surveys,
> - signed letters of interest from tenants,
> - pre-commitments from tenants,
> - documents from past requests for EV charging, or
> - data on the number of tenants with EVs.

Q. Do you recommend any other modifications to the Company's MUD rebate proposal?

A. Yes. For MUDs that do not meet the Company's LI thresholds, because there will be significant make-ready costs, I would recommend that the site host should be able to use the full $5,000 to pay for the charger and/or any make-ready costs. For example, if the site host has separate funding for the EV charger, they should still be able to access the rebate to pay for part of the necessary make-ready upgrades.

Q. What does the Company propose in terms of public charging rebates?

A. According to witness Bennett,

> Stakeholders ranked all the public charging subsegments, including on-route and destination charging, as the most important for utility action because the availability of public charging is critical to reducing range anxiety, which is a key barrier to EV adoption.[161]

Given this, the Company proposes to offer a rebate of $70,000 for on-route DCFC in DAC and rural areas and $50,000 per on-route DCFC in other areas.[162] The Company defines "on-route" as a charger that is located "within one mile of a major throughway exit."[163]

[161] *Id.*, p. 46.

[162] *Ibid.*

[163] *Ibid.*

The Company does not propose any rebates for public Level 2 chargers "as the economics of Level 2 charger deployment are not as challenging, and businesses have other motivation for installation such as increased foot traffic."[164]

Q. Do you support this proposal?

A. I support the Company's decision to expand DCFC rebates to chargers not in DAC or in rural areas. As described above, these investments in public DCFC are critical to overcoming range anxiety and ensuring that the estimated future benefits to other ratepayers (primarily from at-home charging) are borne out.

Q. Do you recommend any changes?

A. Yes. I am concerned that limiting DCFC chargers to "on-route" locations within one mile of a major throughway exit is overly restrictive and may unduly limit the number of participants that benefit. There may be other locations, especially in rural areas, that would serve as appropriate and beneficial locations for a community DCFC. For example, a grocery store on a main road could provide beneficial fast charging but might be excluded from the Company's rebate program if the roadway is not considered a "major throughway" or is not located within on mile of a road that is considered a "major throughway."

[164] *Id.*, p. 47.

I therefore recommend that the Company eliminate the requirement that public DCFC must be "on-route" locations within one mile of a major throughway to qualify for a rebate and instead extend these rebates to all public DCFC locations.

In addition, because there will be significant make-ready costs for any public DCFC, I would recommend that the site host should be able to use the available rebate for the charger and/or any make-ready costs. For example, if the site host has separate funding for the EV charger, they should still be able to access the rebate to pay for part of the necessary make-ready upgrades.

Q. Do you support the Company's decision not to propose any rebates for public Level 2 chargers?

A. No. While it is critical to support expansion of public DCFC, there are also important use cases for public Level 2 chargers including at long-dwell-time locations such as workplaces and shopping areas. These chargers can be especially important for drivers without access to charging at home. Although it is true that Level 2 chargers are less expensive than DCFC, it is not clear on the face of it that there is any difference in the potential motivations of businesses to install a DCFC or Level 2 charger. Witness Bennett claims that site hosts are motivated to install a Level 2 charger because it will bring "increased foot traffic,"[165] but it is unclear why a business would not have the same motivations to install a DCFC. For example, a convenience store that installs DCFC is likely motivated to do so to encourage the sale of snacks, coffee, and other items at the store while the EV driver waits for their

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[165] *Ibid*.

vehicle to complete charging. Because Level 2 chargers are less expensive than DCFC, utility rebates can incentivize more chargers with less funding.

Q. What do you recommend with respect to rebates for Level 2 public chargers?

A. I recommend that the Company make rebates available for public Level 2 chargers. This could be done by (1) adding limited funding (*e.g.*, $5 million) to the public charging program specifically for public Level 2 chargers, and/or (2) allowing public and workplace Level 2 chargers to qualify for the Business Charger Rebate, sharing budget with that proposed for MUD rebates. In either case, these rebates could be structured in a similar manner to the proposed MUD rebates with rebates for Level 2 public chargers covering the full cost of installation in LI communities and $5,000 of the EV charger costs in non-LI communities. Because the costs of Level 2 chargers are lower than DCFC, a relatively small additional budget (e.g., $5 million) could support significant build-out of Level 2 public chargers, supporting different use cases in long-dwell-time locations.

Increased access to workplace charging has been found to increase the likelihood of an employee choosing to drive an EV sixfold.[166] In a similar manner to shared MUD chargers, shared Level 2 chargers at work fill an important gap for drivers who do not have access to their own personal home charger. Recent data from EV charging company ChargePoint indicates that the workplace is the second most popular charging location after home

[166] U.S. Department of Energy, "Workplace Charging Challenge Progress Update 2016: A New Sustainable Commute," 2016, available at https://www.energy.gov/sites/prod/files/2017/01/f34/WPCC_2016%20Annual%20Progress%20Report.pdf.

charging, accounting for 27 percent of all charging sessions in 2023.[167] Providing workplace charging also presents an ideal use case for managed charging. These vehicles are parked most of the day, and the charging infrastructure is used in a repeated pattern reflecting employees' arrival and departure from the office. This predictable usage pattern can allow workplaces to participate in load management with more ease than a general public charging site, with the added advantage is that workplace load will appear in the early mornings and afternoons, balancing the residential charging load which is more likely to increase in the evenings. Given the growth in solar energy generation, this additional daytime load can decrease strain on the grid and allow for greater integration of renewable energy generation.[168]

Q. What does the Company propose with respect to fleet charging rebates?

A. The Company proposes to continue its eFleet Charger Rebate program for school and transit buses by providing a rebate of $70,000 per DCFC. The Company also proposes to continue to offer a $2,500 rebate for fleet owners who install a Level 2 charger. To access a rebate, a fleet customer will need to install a networked charger; share data with DTE; agree to load commitments; in areas with grid constraints, agree to demand ceilings; and, for schools—to access the full $70,000 rebate—install bi-directional chargers.[169]

[167] CBRE, "EV Adoption Creates More Demand for Workplace Charging Stations," May 3, 2024, available at https://www.cbre.com/insights/articles/ev-adoption-creates-more-demand-for-workplace-charging-stations.

[168] Powell, S. et al., *Nature Energy*. "Charging infrastructure access and operation to reduce the grid impacts of deep electric vehicle adoption," Vol 7, available at https://www.nature.com/articles/s41560-022-01105-7, pp. 932-945.

[169] Bennett Direct, p. 49.

Q. Do you support these proposals?

A. Yes. As the Company notes, there are significant opportunities to electrify fleets including funding for transit and school buses from both federal and state programs. It is critical to ensure that the transit agencies and schools are able to install chargers to ensure successful deployment of these new vehicles. Given that the technology for bi-directional chargers is still improving and costs remain higher for these chargers, I would recommend that the Company provide at least partial rebates for schools that are not able to install bi-directional chargers but otherwise meet the rebate program criteria.

Q. What does DTE propose with respect to the Charging Forward CIAC waiver?

A. The Company proposes to eliminate the CIAC waiver. According to witness Bennett,

> Consistent with providing positive rate impacts and affordability benefits accruing to all customers, DTE Electric decided, as part of its TEP, to no longer waive CIAC beyond revenue credits from the existing line extension policy. This is also in alignment with feedback received from key stakeholders.[170]

Q. Are you concerned by this proposal?

A. Yes. First, CIAC policy simply should not be applied to customers using typical Level 2 chargers. Current policy and technology trends establish a strong expectation that EV charging at home will be ubiquitous. There is great risk that if residential customers are expected to pay CIAC when distribution grid upgrades are needed to accommodate EV charging, there will be significant inequities and that CIAC will become a barrier to EV adoption.

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[170] *Id.*, p. 51.

It is very likely, for example, that the first few customers served by a given line transformer can be accommodated without replacing the line transformer but that, at some point, one unfortunate customer's acquisition of an EV will trigger a need to replace the transformer. Under normal CIAC policy, that customer would bear the full cost of the replacement transformer. Customers that subsequently acquire an EV would likely not be required to pay CIAC for a transformer upgrade because it has already been upgraded. This would be manifestly unfair, as the need to replace the transformer to accommodate EV charging would in fact have been "caused" by *all* of the customers that acquired an EV before the transformer upgrade and the transformer upgrade will benefit the customers that subsequently acquire an EV. Similarly, an increase in EV charging at both residential and commercial locations may trigger voltage regulation or capacity upgrade needs in a circuit. Again, it would be manifestly unfair to require the random customer that just so happens to be unlucky enough to trigger the circuit upgrade to pay that cost.

Q. What solution would you propose to fix this inequity that results from the application of normal CIAC policy to distribution upgrades driven by expanded EV charging?

A. The only appropriate resolution is to socialize the cost of distribution system upgrades made necessary by the accumulation of EV charging load. Even as CIAC charges to individual customers create the likelihood that there will be unfair charges to individual customers that trigger distribution system upgrades, the Company will receive incremental revenues from all customers that are charging EVs on those same facilities. This is one reason that the foundation for transportation electrification policy should be that all EV charging revenue counts toward recovering the costs of EV charging, but that the BCA and the evaluation of net revenue available to support EV charging should reflect the expected costs of system-wide distribution upgrades to support EV charging.

I therefore recommend that the Company's proposal to eliminate the CIAC policy waiver should simply be rejected for Level 2 charging because such charging is expected to be ubiquitous, with most costs associated with upgrading shared facilities driven by aggregate demand and EV revenue from all charging being appropriately available to cover those costs.

Q. Is your recommendation different with respect to CIAC policy for DCFC?

A. Not necessarily. DCFC charging does present a somewhat different case in that a DCFC site may represent a large enough demand to trigger material upgrades of facilities that are local to the DCFC site. In these instances, existing CIAC policy seems applicable. However, much of the rationale for exempting Level 2 charging from CIAC also applies to DCFC. I used the U.S. Department of Energy's Electric Vehicle Infrastructure ("EVI")-Pro Lite tool[171] to determine the number of DCFC needed to support complete electrification of Michigan's light-duty fleet. The EVI-Pro Lite estimates that this would require 49,503 DCFC ports, which is almost seven ports for each distribution circuit in Michigan.[172] It is therefore reasonable to think of DCFC as becoming relatively ubiquitous

[171] U.S. Department of Energy, Alternative Fuels Data Center, "Electric Vehicle Infrastructure Toolbox," available at https://afdc.energy.gov/evi-x-toolbox - /evi-pro-ports?region_type=state&charging-state=MI&vehicles=7752700&phev-support=half&res-access=48&phev-share=1&scenario=2&pev-car=30&pev-suv=44&pev-pickup=20&pev-van=6.

[172] U.S. Energy Information Administration, "Annual Electric Power Industry Report, Form EIA-861 detailed data files," 2022 final data, available at https://www.eia.gov/electricity/data/eia861/.

as EV deployment increases. Furthermore, as described above, adequate availability of public charging for road trips is essential for enabling the adoption of EVs and should therefore appropriately be credited with enabling the revenue produced by charging at home and at other locations with Level 2. It is therefore also appropriate to waive CIAC policy for *public* DCFC because public DCFC are a form of shared facility available for use by many customers, which produce revenues for the utility indirectly by enabling broad EV adoption and increased sales from charging occurring at locations other than the particular DCFC site.

D. DCFC COST OF SERVICE STUDY

Q. In its final order in DTE's most recent rate case, Case No. U-21297, the Commission ordered the Company to include in this case an analysis of the cost of service for DCFC. What methodology did the Company use to develop the proposed EV Fast Charger Rate Design?

A. The Company's analysis of DCFC cost of service is presented in the testimony of witness Habeeb J. Maroun.[173] Witness Maroun modified the Company's principal cost of service study to consider DCFC as a separate class, using 21 customers for which the Company had usable data. His results were presented in Exhibit A-16 Schedules F1.6, F1.7, and F1.8. Aside from the separation of DCFC customers, the alternate cost of service study was not materially different from the Company's principal cost of service study.

[173] Revised Direct Testimony of Habeeb J. Maroun on behalf of DTE Electric Company, Case No. U-21534, pp. 27-28.

Q. Should that cost-of-service study be applied to create a DCFC rate in this case?

A. Not in my opinion. There are two limitations to consider. First, the number of customers was small and may likely not be representative. Second, given the immaturity of the market, usage of these sites likely does not represent the expected utilization rate in coming years as EV deployment increases until it reaches an eventual point of consistent uptake (*e.g.*, a certain market equilibrium). These DCFC sites likely have individual customer and class peak demands that may approximate what those demands will be with increased EV deployment, but the total energy usage at these sites is currently significantly less than what it will be in the future. As such, present revenue requirements per kWh of DCFC are likely well above those that will be required in the future.

The Company appears to agree with this view, stating that

> The Company acknowledges the merit in continuing this discussion. The data constraints and generally small customer set indicate that this proposal should be used as a starting point for discussion only and not as a rate to be implemented at the conclusion of this case.[174]

Q. What rate design should be applied to DCFC sites in this case?

A. Customers adding DCFC to an existing meter should continue to have the option to use their existing rate schedule. Additionally, existing or new customers should continue to have the option to take service on rate schedule D3 with exemption from the 1000 kW demand restriction. Currently, rate schedule D3 exempts EV charging stations from the 1000 kW demand restriction only until January 1, 2026. I recommend that both existing

[174] Revised Direct Testimony of Aaron Willis on behalf of DTE Electric Company, Case No. U-21534, p. 36.

and new customers should be allowed to access this rate schedule without the demand restriction for at least four additional years, until January 1, 2030. This should provide sufficient time for DCFC usage to approach a market equilibrium, though that will need to be assessed at the time. While it may still be premature to establish EV-specific rates even by 2030, my recommendation will ensure that demand-based rates do not inhibit the expansion of DCFC for sites with high demand but low utilization rates in the interim.

III. <u>C&I BATTERY STORAGE PILOTS</u>

Q. What is the C&I Battery Storage pilot?

A. According to witness Keegan O. Farrell,

> The C&I battery storage pilot is a behind-the-meter (BTM) lithium-ion phosphate battery energy storage system (BESS) that will be located at two customers' sites. It is designed to test the ability to achieve peak demand shaving or shifting during [demand response] DR events.[175]

The Company has identified only one C&I customer for this pilot but has already ordered the batteries and switchgear component and anticipates that both batteries will be operational by the end of 2025.[176] The Company initially anticipates that the batteries will be utilized for "no more than 30 planned DR events per year and five emergency DR events, with at least one-hour customer notice, per year."[177]

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[175] Direct Testimony of Keegan O. Farrell on behalf of DTE Electric Company ("Farrell Direct"), Case No. U-21534.

[176] *Id.,* p. 30.

[177] *Id.,* p. 31.

Q. Did the Commission previously approve funding for this pilot?

A. In part. In the last DTE general rate case (Case No. U-21297), the Commission approved funding for the first battery, but not the second ($1,990,360, or half of the proposed capital spend) because the second customer had not yet been identified.[178]

Q. Has the Company identified a second customer?

A. No. According to witness Farrell, "the Company expects to have a second customer secured in the first half of 2024."[179]

Q. What do you conclude about the funding sought by the Company for this pilot?

A. Given that the Company still has not yet secured a second customer for this pilot, it does not appear that the circumstances upon which the Commission based its decision in the last general rate case (Case No U-21297) have changed. As such, I do not believe that the Commission should approve the proposed spending for the second battery at this time. The Company historically has filed a new rate case as often as it is allowed to do so (i.e., every 12 months). As such, this spending, if a second customer is identified, can be approved in the next rate case.

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[178] Michigan Public Service Commission, Case No. U-21297, "Order in the matter of the application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority," December 1, 2023, p. 247.

[179] Farrell Direct, p. 31.

Q. Have you previously opposed utility ownership of behind-the-meter batteries?

A. Yes. I have strongly opposed utility ownership of behind-the-meter batteries, including in the case of a residential battery pilot proposed by the Company in Case No. U-20836.[180] In that case, the Company proposed to enroll 5 MW of customer-sited, utility-owned, behind-the-meter batteries in a pilot program where the customer would only have access to the battery for outage events and DTE would otherwise control it. This pilot proposal was similar to a proposal (which I also opposed) from Consumers Energy in Case No. U-20963 except that Consumers Energy proposed both a utility-owned component and a "Bring Your Own Device" customer-owned component.[181]

Q. Why do you believe that utility-ownership of behind-the-meter customer-sited batteries is inappropriate?

A. Investor-owned utilities like DTE Electric are considered a natural monopoly because it is not efficient or economic to have more than one provider of a particular commodity or service. In other words, contrary to our economic system's general desire and support for multiple competitors in the marketplace, a utility like DTE Electric is allowed to control aspects of the electric service market because it would not be practical to have multiple entities operating in this space, both figuratively and literally. In exchange for not having competitors and to protect consumers from the natural power of a monopoly, the Company is subject to regulation by the Commission. Despite being regulated, a monopoly public

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[180] Direct Testimony of Dr. Laura S. Sherman on behalf of The Michigan Energy Innovation Business Council and Institute for Energy Innovation, Case No. U-20836, pp. 33-45.

[181] Direct Testimony of Priya D. Machi on behalf of Consumers Energy, Case No. U-20963.

utility still wields substantial influence through its general access to customers, the customer information it collects, regular (at least monthly) communication with customers, guaranteed cost-recovery and profit, general brand recognition, and socialized cost recovery. This reality provides a public utility a significant advantage over third parties in the marketplace who do not benefit from having a monopoly. For this reason, it is very important that a monopoly public utility not be allowed to intrude and influence the marketplace where competitors exist to provide a commodity or service.

For these reasons, in general, I have consistently recommended that the Commission follow the prudent example of the New York Public Service Commission ("NYPSC"). The NYPSC imposed a general policy of utility exclusion from behind-the-meter markets but permitted certain focused and limited exceptions to that rule, which were intended to be facilitative of, rather than competitive with, the unregulated market. Specifically, the NYPSC found that utility ownership may be permitted in the following circumstances:

> 1. Procurement of [distributed energy resources] has been solicited to meet a system need, and a utility has demonstrated that competitive alternatives proposed by non-utility parties are clearly inadequate or more costly than a traditional utility infrastructure alternative;
>
> 2. A project consists of energy storage integrated into distribution system architecture [referring to systems on utility property];
>
> 3. A project will enable low- or moderate-income residential customers to benefit from [distributed energy resources] where markets are not likely to satisfy the need; and

4. A project is being sponsored for demonstration purposes.[182]

Q. What did the Commission decide in those previous cases regarding the proposed residential behind-the-meter battery storage pilots?

A. In Case No. U-20836, the Commission denied DTE Electric's residential behind-the-meter battery storage pilot, stating:

> Accordingly, the Commission adopts the ALJ's findings and conclusions and rejects the residential battery pilot. The Commission is very supportive, in general, of utilities implementing residential battery pilots, and is eager to see development of innovative programs in this area. The Commission favors some elements of DTE Electric's residential battery proposal, for example, the income-eligible aspect where customers receive batteries at no cost, but would like to see changes in other elements, such as broader benefits to participants, the company-owned batteries requirement, ineligibility of solar customers, and the narrow focus on the provision of back-up power and limited emphasis on company learnings as opposed to a broader focus on customer benefits. The Commission finds the intervenors' comments persuasive, as a whole, and notes concerns about the utility inserting itself into the home battery market in a manner that would, perhaps, unfairly inhibit private sector competition. The Commission agrees with the Staff's comment that customers would receive better price signals through third-party ownership of batteries because there would be no program costs subsidized by non-participants. . . .[183]

[182] New York Public Service Commission, Docket No. 14-M-0101, "Order Adopting a Regulatory Policy Framework and Implementation Plan," February 26, 2015, available at https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={0B599D87-445B-4197-9815-24C27623A6A0}. The NYPSC later reaffirmed these principles: *See* NYPSC, Docket No. 18-E-0130, Order Establishing Energy Storage Goal and Deployment Policy, December 13, 2018, pp. 43–45, available at https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BFDE2C318-277F-4701-B7D6-C70FCE0C6266%7D.

[183] Michigan Public Service Commission, Case No. U-20836, "Order in the matter of the application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority," November 18, 2022, pp. 356-357.

In Case No. U-20963, the Commission also rejected Consumers Energy's proposed residential behind-the-meter battery pilot. In doing so, the Commission highlighted a number of concerns:

> However, while a pilot to utilize battery storage as back-up for resiliency service is a novel proposal, the Commission declines to adopt the company's proposal at this time. The Commission notes several concerns with the pilot as proposed, including the fact that rather than seeking to value the full range of benefits batteries can provide, the pilot as proposed limits a participating customer's utilization of the battery system only to providing back- up power in the event of a power outage, while also failing to provide for the range of other benefits the systems can offer to both participating customers and the company's broader customer base. The Commission agrees with the ALJ that it would like to see the company work with stakeholders and come back with a more refined proposal.[184]

Q. What recommendations do you have for the future of the C&I Battery Storage pilot?

First, as stated above, although the Commission has already approved the spending for part of this pilot, I recommend that no further spending be approved. Second, I believe that the Company should shift its efforts away from this pilot to focus on rate design changes or pilots that can benefit a larger group of customers without utility-ownership of behind-the-meter batteries.

According to witness Farrell,

> Pilots are potential programs focused on understanding technology or design and determining whether they can become full-scale programs that will deliver accountable peak demand reductions or shifts in energy consumption.[185]

[184] Michigan Public Service Commission, Case No. U-20963, "Order 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," December 22, 2021, pp. 323–324.

[185] Farrell Direct, p. 13.

In my opinion, a pilot like the C&I Battery Storage pilot that has required more than two years to enroll only one customer is not a sustainable pilot that can likely become a full-scale program. Instead, I believe, as outlined below, that there are more efficient ways to accomplish the objectives of the C&I Battery Storage pilot with customers through the use of innovative rate designs and involvement of third parties.

Q. Have C&I behind-the-meter battery storage projects been successful in other areas of North America?

Yes, several North American markets have effectively attracted C&I behind-the-meter battery energy storage systems.[186] There are different approaches and programs that have successfully encouraged C&I behind-the-meter battery storage, which I describe in more detail below, but a common element across those markets is the role of third-party developers working directly with the C&I customers. In my opinion, the challenges the Company has encountered trying to identify a second customer to participate in the C&I Battery Storage pilot may in part be because it is marketing a pilot where most of the benefits from the battery storage system are retained by the utility. As described by witness Farrell, the objectives of the pilot are to:

- Engage with customers to better understand their interest in hosting and potentially operating a BESS;
- Gain operational experience on battery installation, management, and control interfaces when the system is located at a customer's site as opposed to a Company site;

[186] McNamara, W., Passell, H., and Olinsky-Paul, T., Clean Energy States Alliance and Sandia National Laboratories, "States Energy Storage Policy: Best Practices for Decarbonization," February 2023, available at https://www.cesa.org/resource-library/resource/states-energy-storage-policy-best-practices-for-decarbonization/.

- Assess feasibility for sharing asset control between customer and the Company; and
- Evaluate the effectiveness of the BESS to achieve system peak demand reduction when a demand response event is called by the Company;
- Assess customer's actions to achieve demand charge and overall bill reductions;
- Facilitate the understanding of multiple energy storage values compensation models, and the integration of battery storage in wholesale markets to support tariff development as contemplated by the Commission's Order in MPSC Case No. U-21032.[187]

Although some of these objectives benefit the C&I customer, most of these objectives focus on the Company's learnings, market access, and future financial benefit. In contrast, when working with a customer to design a behind-the-meter battery solution, and competing with other providers, third-party developers are necessarily focused on the optimizing the benefits for the customer. Given appropriate market signals, these C&I batteries can still provide the same benefits to the grid and the utility.

Q. What policies have made C&I behind-the-meter battery storage projects successful in other areas of North America?

A. There are a number of rate design, utility program elements, and incentive structures that have made C&I behind-the-meter battery energy storage projects successful. State level incentives, such as those provided in California[188] have encouraged deployment as have appropriate rate design signals such as those provided in Ontario. I will focus here on rate

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[187] Farrell Direct, pp. 29-30.

[188] McNamara, W., Passell, H., and Olinsky-Paul, T., Clean Energy States Alliance and Sandia National Laboratories, "States Energy Storage Policy: Best Practices for Decarbonization," February 2023, available at https://www.cesa.org/resource-library/resource/states-energy-storage-policy-best-practices-for-decarbonization/.

design options given that these are more in the direct purview of the Company and the Commission than state incentive programs.

In Ontario, all electric customers pay a Global Adjustment charge (“GA”),[189] but C&I customers with more than 5 MW of load can reduce their GA charge through a load management program called the Industrial Conservation Initiative (“ICI”).[190] The ICI was designed to help the province defer the need for investments in new electricity infrastructure that would otherwise be needed by incentivizing eligible C&I customers to reduce demand during peak periods.[191] C&I customers who participate in the ICI pay a GA charge based on their contribution to the top five peak hours of energy use (“Coincident Peaks” or “CPs”) in Ontario over a 12-month base period (May 1 to April 30), and are referred to as “Class A” customers. The Independent Electricity System Operator of Ontario (“IESO”) calculates and publishes peak demand information to help customers identify when one of those five peak hours may occur to ensure that Class A customers have the ability to appropriately reduce their demand or switch load to a behind-the-meter battery.[192] Given historically high GA charges, as detailed by a recent study conducted by researchers from Ryerson University and Amp Solar Group, if a C&I customer can use a

[189] Electricity Act, 1998, Ontario Regulation 429/04, Adjustments under Section 24.33 of the Act, July 1, 2023, available at https://www.ontario.ca/laws/regulation/040429#BK2.

[190] Hydroone, “Industrial Conservation Initiative (ICI),” available at https://www.hydroone.com/business-services/commercial-industrial-generators-and-ldcs/commercial-industrial-customers/industrial-conservation-initiative.

[191] Hydroone, “Industrial Conservation Initiative: Class A Methodology for Billing the Global Adjustment,” available at https://www.hydroone.com/businessservices_/industrial-generators-ldcs/Documents/2024_ICI_Presentation.pdf.

[192] IESO, “Peak Tracker,” available at https://www.ieso.ca/Sector-Participants/Settlements/Peak-Tracker.

behind-the-meter battery to decrease load during those five peak hours, it can easily justify the cost of the battery.[193] The ICI not only provides opportunities for customers to save money with batteries, but it has also grown so large that the IESO stated in the 2024 Annual Planning Outlook that ICI is one of two load modifiers factored into its load forecast, and that the initiative has "material impacts on the forecasted seasonal peak demand of each year."[194]

Other similar rate designs where C&I charges are set by consumption during a specified number of CPs have led to increases in C&I behind-the-meter battery energy storage deployment. For example, in Massachusetts transmission rates are allocated to each class based on the class's contribution to each month's coincident peak (called the "12 CP" method).[195] Certain utilities, like Eversource Energy ("Eversource"), offer tariffs that price these transmission costs based on the customer's actual electricity use at the time of the system peak.[196] In a recent Eversource general rate case, the Massachusetts Department of Public Utilities required Eversource to expand the option for C&I customers to opt-in to

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[193] Kadri, A., Mohammadi, F., and Awadallah, M., *Applied Sciences*, "Minimization of Global Adjustment Charges for Large Electricity Customers Using Energy Storage – Canadian Market Case Study," November 30, 2020, vol. 10, issue 23, available at https://www.mdpi.com/2076-3417/10/23/8585.

[194] Independent Electricity System Operator of Ontario, "Annual Planning Outlook, Ontario's electricity system needs: 2025 – 2050," March 2024, available at https://www.ieso.ca/Powering-Tomorrow/2024/Six-Graphs-and-a-Map-2024-Annual-Planning-Outlook-and-Emissions-Update.

[195] Massachusetts Department of Public Utilities, D.P.U. 22-22, "Order in Petition of NSTAR Electric Company, doing business as Eversource Energy, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Plan," November 30, 2022.

[196] *Ibid.*

these tariffs (like Eversource's Rate T-5) to all C&I customers.[197] C&I customers who install behind-the-meter battery storage systems and enroll in a rate like Eversource's T-5 can reduce their costs by precisely decreasing their load during system monthly CPs and, thereby, lowering their transmission charges. These cost savings can then help justify the upfront costs of the battery storage systems.

In addition to rate design solutions that encourage C&I battery storage deployment, several states have established utility rebate programs for behind-the-meter storage systems. For example, in Illinois, utilities are required to establish tariffs that provide rebates of at least $250 per kWh to customers who install solar plus storage systems for the benefits that those systems provide to the grid.[198] Similarly, the ConnectedSolutions program in Massachusetts provides compensation in exchange for customer battery dispatch (i.e., "pay for performance") at times of peak demand when required by the utility.[199]

IV. CONCLUSIONS AND RECOMMENDATIONS

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

A. I recommend that the Commission:

- Require the Company in its TEP BCA to account for all (i.e., 100 percent) of the expected increase in revenue from increased EV charging through 2030;

[197] *Ibid.*

[198] Namara, W., Passell, H., and Olinsky-Paul, T., Clean Energy States Alliance and Sandia National Laboratories, "States Energy Storage Policy: Best Practices for Decarbonization," February 2023, available at https://www.cesa.org/resource-library/resource/states-energy-storage-policy-best-practices-for-decarbonization/.

[199] *Ibid.*

- Require the Company to revise its TEP BCA to account for increasing utilization rates over time for public EV chargers;
- Require the Company to revise its TEP BCA to account for societal benefits including greenhouse gas and criteria pollutant emissions reductions;
- Require the Company to increase the income threshold for Home Charger Rebates to 400 percent of the federal poverty level and allow customers to self-attest to their income, and/or offer Home Charger Rebates to customers living in DACs;
- Encourage the Company to clarify that the requirement to demonstrate tenant interest for the MUD rebates is limited to self-attestation;
- Require the Company to allow non-LI MUDs to use the full $5,000 rebate to pay for the charger and/or any make-ready costs;
- Require that the Company eliminate the requirement that public DCFC must be "on-route" within one mile of a major throughway to qualify for a rebate;
- Require the Company to allow public DCFC site hosts to use any available rebate for both the charger and/or any make-ready costs;
- Require the Company to add additional rebates for public Level 2 chargers either by (1) adding limited funding (e.g., $5 million) to the public charging program for public Level 2 chargers, and/or (2) allowing public and workplace Level 2 chargers to qualify for the Business Charger Rebate, sharing budget with that proposed for MUD rebates;
- Require the Company to develop a make-ready infrastructure rebate program for public charger infrastructure;

- Reject the Company's proposal to eliminate the CIAC waiver for both Level 2 and DCFC;
- Do not require the Company to create a DCFC rate in this case and instead allow customers adding DCFC to an existing meter to use their existing rate schedule;
- Require the Company to allow existing or new customers installing DCFC to have the option to take service on rate schedule D3 with exemption from the 1000 kW demand restriction until at least January 1, 2030;
- Reject the Company's proposed spending for the second customer in the C&I Battery Storage Pilot; and
- Require the Company, instead of continuing the C&I Battery Storage Pilot, to work with stakeholders to develop new rate designs or pilot programs to benefit a larger group of customers without utility-ownership of behind-the-meter batteries.

Q. Does that complete your testimony?

A. Yes.

STATE OF MICHIGAN

MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of the Application of **DTE Electric Company** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	)	**Case No. U-21534**

DIRECT TESTIMONY OF JUSTIN R. BARNES

ON BEHALF OF

THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL,

INSTITUTE FOR ENERGY INNOVATION.

AND

ADVANCED ENERGY UNITED

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name, business address, and current position.

A. My name is Justin R. Barnes. My business address is 1155 Kildaire Farm Rd., Suite 202, Cary, North Carolina, 27511. My current position is President of EQ Research LLC.

Q. On whose behalf are you submitting testimony?

A. I am submitting testimony on behalf of the Michigan Energy Innovation Business Council ("Michigan EIBC"), the Institute for Energy Innovation ("IEI") and Advanced Energy United ("United"), collectively referred to as "MEIU."

Q. Have you previously submitted testimony before the Michigan Public Service Commission ("Commission" or "MPSC")?

A. Yes. I submitted testimony in MPSC Case No. U-20963, a general rate case, on a Consumers Energy Company home battery storage pilot program; MPSC Case No. U-20836, a general rate case, on a DTE Electric Company ("DTE" or "the Company") proposal for changes to its distributed generation ("DG") rider and the establishment of a residential demand rate; and MPSC Case No. U-21297,[1] DTE's last general rate case, wherein I recommended that DTE be required to offer develop time-of-use ("TOU") rate schedules for commercial and industrial ("C/I").

[1] Direct Testimony of Justin R. Barnes on behalf of MEIU, Case No. U-21297, 6 Tr 4232–4251 ("Barnes U-21297 Direct Testimony").

Q. Please describe your educational and occupational background.

A. I obtained a Bachelor of Science in Geography from the University of Oklahoma in Norman in 2003 and a Master of Science in Environmental Policy from Michigan Technological University in 2006. I was employed at the North Carolina Solar Center at N.C. State University for roughly five years as a Policy Analyst and Senior Policy Analyst.[2] During that time I worked on the Database of State Incentives for Renewables and Efficiency ("DSIRE") project, and several other projects related to state renewable energy and energy efficiency policy. I joined EQ Research in 2013 as a Senior Analyst, became the Director of Research in 2015, and President in May 2023. In my current position, I coordinate and contribute to EQ Research's various research projects for clients, provide oversight of EQ Research's electric industry tracking services and consulting projects, and perform customized research and analyses to fulfill client requests.

Outside of Michigan I have submitted testimony before utility regulatory commissions in Colorado, Georgia, Hawaii, Indiana, Kentucky, New Hampshire, New Jersey, New York, North Carolina, Oklahoma, South Carolina, Texas, Utah, and Virginia, West Virginia, Wisconsin, and the City Council of New Orleans,[3] on various issues related to distributed generation ("DG") and distributed energy resource ("DER") policy, rate design, cost of service and cost allocation, avoided cost rates for qualifying facilities ("QFs"), and customer-sited battery storage program design. These individual regulatory proceedings have involved a mix of general rate cases and other types of contested cases. My curriculum

[2] The North Carolina Solar Center is now known as the North Carolina Clean Energy Technology Center.
[3] The City Council of New Orleans regulates the rates and operations of Entergy New Orleans in a manner equivalent to state utility regulatory commissions.

vitae is attached as Exhibit MEIU-22 (JRB-1). It contains summaries of the subject matter I have addressed in each of these proceedings.

Q. Please describe the purpose of your testimony and how it is organized.

A. The purpose of my testimony is to address DTE's proposals for establishing two opt-in TOU rates for C/I customers, which DTE has designated as Rate Schedule D3.11 (applicable to customers that take service at secondary voltage) and as Rate Schedule D14 (applicable to customers that take service at primary voltage). At a general level, I support DTE's proposals, which are largely consistent with the recommendations that I made for establishing C/I TOU rates in Case No. U-21297.[4] However, I recommend several modifications to the Company's proposals related to their specific rate design, deployment timelines, and availability limitations. I also make accompanying recommendations regarding the availability of customer rate comparison reports that would assist customers in evaluating whether or not enrollment in the C/I TOU rates would be beneficial to them.

My testimony is organized into the following sections:

- Section II: Presents background information on the Company's proposed C/I TOU rates, their design, and tariff terms.
- Section III: Discusses my proposed modifications to the Company's proposals, addressing: (a) rate design, (b) availability limitations, and (c) deployment timeline.
- Section IV: Discusses my proposal that DTE provide C/I customers with rate comparison reports to aid them in their choice of rate schedule.

[4] See Barnes U-21297 Direct Testimony.

- Section V: Presents my concluding remarks and summarized recommendations.

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

A. Yes. I am sponsoring the following exhibits:

- Exhibit MEIU-22 (JRB-1) – Curriculum Vitae of Justin R. Barnes
- Exhibit MEIU-23 (JRB-2) – Discovery Response MEIUDE-1.20(a)
- Exhibit MEIU-24 (JRB-3) – Discovery Response MEIUDE-1.19(a)
- Exhibit MEIU-25 (JRB-4) – Discovery Responses MEIUDE-1.18 (a), (e) & (f)
- Exhibit MEIU-26 (JRB-5) – Discovery Response MEIUDE-1.18(b)
- Exhibit MEIU-27 (JRB-6) – Discovery Response MEIUDE-1.18 (d)
- Exhibit MEIU-28 (JRB-7) – Discovery Response MEIUDE-1.27(a)
- Exhibit MEIU-29 (JRB-8) – Discovery Response MEIUDE-3.3(b)
- Exhibit MEIU-30 (JRB-9) – Discovery Response MEIUDE-3.3(a)
- Exhibit MEIU-31 (JRB-10) – Illustrative Rate Comparison Report Format

Q. Please summarize your recommendations on DTE's C/I TOU rate proposals.

A. I recommend that the Commission approve the establishment C/I TOU rates with the following modifications:

1. The C/I TOU rates should consist of three (3) individual rate schedules that reflect rates mapped to revenue neutrality with the existing D3, D4, and D11 Rate Schedules, modifying the Company's proposal by creating a TOU corollary for Rate Schedule D4 in addition to those proposed for Rate Schedules D3 and D11.

2. The C/I TOU rates should use a common on-peak pricing window of 1-5 PM, weekdays only, which has the effect of modifying the 11 AM – 7 PM non-holiday weekdays on-peak window that the Company proposed for Rate Schedule D14.
3. The Company's proposed enrollment limitations (i.e., caps) on the individual proposed C/I TOU rate schedules should be eliminated in their entirety.
4. The C/I TOU rates should be made available for customer enrollment within three (3) months of the Commission's final order in this case.
5. DTE should be directed to develop a rate comparison tool that can model C/I rates and that produces a standardized report as an output, and DTE should make such reports available by the time the new C/I TOU rates are made available.

These changes, both individually and collectively, will place DTE's C/I TOU rates on a more solid and effective foundation consistent with cost causation, rate attractiveness to customers, and the ability to respond to TOU price signals.

II. BACKGROUND INFORMATION ON DTE'S C/I TOU RATES PROPOSALS

Q. Why did DTE propose to establish C/I TOU rates in its present rate case application?

A. The Commission's December 1, 2023 Order in Case No. U-21297 directed the Company to do so, stating "[f]or its next general rate case, DTE Electric Company shall develop and present optional time-of-use rates for its commercial secondary and primary customers."[5] This directive was based on an Administrative Law Judge ("ALJ") recommendation in the Proposal for Decision in which the ALJ agreed that optional TOU rates could be beneficial for C/I customers.[6] During the case, the Company took exception to the ALJ's

[5] December 1, 2023 Order in Case No. U-21297 ("U-21297 Order") at 372.
[6] Proposal for Decision in Case No. U-21297, Filing No. U-21297-0621, at 819.

recommendation, arguing among other things that "there is no demonstrated shortcoming in the Company's rate options."[7] Despite DTE's objections, the Commission found it to be reasonable to require DTE to develop C/I TOU rates.

Q. Please briefly summarize the Company's C/I TOU rates proposal.

A. The Company proposes to establish two (2) new rate schedules, one for customers that take service at secondary voltage (proposed Rate Schedule D3.11) and one for customers that take service at primary voltage (proposed Rate Schedule D14). Rate Schedule D3.11 is mapped to achieve revenue neutrality with Schedule D3, the secondary voltage "General Service" rate.[8] Rate Schedule D14 is mapped revenue neutrally to Schedule D11, the standard primary voltage rate.[9] The Company did not provide a proposal for a revenue neutral TOU rate mapped to Rate Schedule D4, which is designated as its "Large General Service" rate.

With respect to overall TOU structure, both proposed C/I TOU rate schedules utilize a seasonal two-period (on- and off-peak) pricing period design, with a single off-peak rate and a moderate on-peak to off-peak price differential. The price differential is based on the relative difference in the locational marginal price ("LMP") of energy according to the price windows from 2020 to 2022.[10] The distribution rates use the same rate and rate design as the base C/I rate schedule. Table 1 shows several further key details of the Company's proposed C/I TOU rates.

[7] U-21297 Order at 330 (quoting DTE Exceptions to PFD, Case No. U-21297, Filing No. U-21297-0632, at 256).
[8] Direct Testimony of Aaron Willis on behalf of DTE Electric Company, Case No. U-21297 ("Willis Direct), at 31.
[9] *Ibid.*, p. 41.
[10] *Ibid.*, at 42.

Table 1: Key Design Details of Proposed C/I TOU Rates[11]

TOU Rate Schedule	Standard Rate Schedule	On-Peak Window	On-Peak Supply Rate Differential Ratios[12]	Enrollment Cap	Contract Term
D3.11	D3	1-5 PM, weekdays	Summer: 1.68 Winter: 1.07	1,000 customers	12 months
D14	D11	11 AM – 7 PM, non-holiday weekdays	Summer: 1.68 Winter: 1.16	50 MW (contract capacity)	36 months

Q. When does the Company propose to make these rates available to customers?

A. For both rates, DTE states that it “intends” to make the rate available by December 31, 2025, the end of the projected test year.[13] Based on the current case schedule, the December 31, 2025 date corresponds to a delay of roughly 11 months after the expected late-January 2025 Commission Order in this case.

Q. Are there any other significant design elements of the Company’s proposed C/I TOU rates that you would like to mention?

A. Yes. In calculating the D3.11 rates, the Company modified the empirical billing determinants based on hourly D3 class loads by assuming an on-peak to off-peak load shift of 8.2% during summer months and 3.3% during winter months.[14] This has the effect of increasing rates across all pricing periods because it decreases the amount of electricity assumed to be purchased at higher rates during the on-peak pricing periods.[15] Such an

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[11] Table 1 is based on details discussed in Willis Direct at pages 31–34 and 41–43.

[12] For D3.11, DTE’s testimony (Willis Direct, p. 34) specifies rate differentials of 1.38 (summer) and 1.04 (winter) but those ratios are based on the total volumetric rate including the D3.11 volumetric distribution rate. The distinction between supply and distribution rates does not affect proposed Rate Schedule D14 because the distribution rate for Rate Schedule D14 is demand-based, consistent the Rate Schedule D11.

[13] Willis Direct, pp. 34, 43.

[14] *Ibid*., p. 33.

[15] Off-peak rates increase despite the higher amount of assumed electricity use during off-peak periods in order to retain the same seasonal pricing differential.

adjustment was not made to the billing determinants proposed for use in calculating the rates for Rate Schedule D14.

Also, as I previously noted but wish to further highlight, DTE has proposed two (2) C/I TOU rates mapped to existing rate schedules, but C/I customers are served under three (3) core rate schedules. Missing from the Company's proposal is a TOU rate designed to be revenue neutral to Rate Schedule D4 (the Large General Service rate). As I will explain in Section II(A) of my testimony, the omission of a TOU rate mapped to Rate Schedule D4 will inhibit enrollment in a TOU by Rate Schedule D4 customers because proposed Rate Schedule D3.11 as mapped to Rate Schedule D3 is more expensive, on average, than Rate Schedule D4. This average price difference is exacerbated by the Company's proposed adjustments to the D3.11 billing determinants to account for potential load-shifting by participants, which as I previously described, results in the average rate for proposed Rate Schedule D3.11 being higher than the average rate for Rate Schedule D3. That is, on an average volumetric ($/kWh) basis, Rate Schedule D3 is more expensive than Rate Schedule D4, and proposed Rate Schedule D3.11 is more expensive than Rate Schedule D3.

II. PROPOSED MODIFICATIONS TO DTE'S PROPOSALS

A. THE C/I TOU RATES SHOULD INCLUDE A TOU RATE THAT IS MAPPED TO RATE SCHEDULE D4

Q. Please describe the role that Rate Schedule D4 fills within the Company's C/I rates.

A. The Company's secondary voltage C/I rate schedules are designated as D3 and D4. As I previously described, Rate Schedule D3 is effectively the "small commercial" rate, whereas Rate Schedule D4 is effectively the "large commercial" rate. This distinction is based on the differences in their respective rate designs. Rate Schedule D3 uses a purely volumetric ($/kWh) rate design, whereas Rate Schedule D4 contains demand charges ($/kW) for both the power supply and distribution portions of the rate. Demand rates are financially preferrable to customers that have relatively higher load factors (i.e., more constant loads), which by and large tend to be more prevalent among customers with higher overall demands (i.e., larger customers).[16] For that reason, Schedule D4 tends to be a more attractive rate schedule for secondary voltage customers with larger loads, whereas Schedule D3 tends to be more attractive to secondary voltage customers with smaller loads.

Q. Please explain why this distinction is relevant from the standpoint of the deployment of C/I TOU rates.

A. The development of a revenue-neutral TOU rate requires the delineation of usage from an existing "base" rate schedule/class into the pricing periods associated with the new TOU rate while retaining the same overall billed usage determinants and projected revenue amount. As a consequence, the new TOU rate features the same average volumetric rate ($/kWh) as the underlying base rate schedule. This is relevant to the development of a secondary voltage commercial TOU rate because there are two major secondary rate schedules, D3 and D4, and those two rate schedules have different usage determinants, different revenue requirements, and different average volumetric rates.[17]

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[16] As with any generalization, there are exceptions to this. In practice, customers on each individual rate schedule exist along a spectrum of load size and load factor.

[17] Schedules D3 and D4 also differ from the standpoint of Distribution rates and Distribution Surcharges, although not all surcharges are based on the customer's underlying base rate schedule.

Specifically, the average volumetric rate for the Power Supply portion of Schedule D3 is 8.48 cents/kWh, whereas the average volumetric rate for the Power Supply portion of Schedule D4 is 7.87 cents/kWh.[18] DTE has proposed that D3.11 be mapped to the Power Supply usage determinants of Schedule D3, producing an average volumetric rate of 8.48 cents/kWh.[19] However, this same average rate would also apply to customers that currently take service under Schedule D4 if they were to elect to take the proposed TOU rate service. In effect, this introduces a poison pill for a D4 customer that wishes to take service under a TOU rate because in order to take TOU service, they must enroll in a rate that is, on average, 0.61 cents/kWh (7.8%) more expensive than the D4 rate from the standpoint of the Power Supply charges upon which Schedule D3.11 is designed.[20]

Q. How can this disincentive to TOU rate enrollment by Schedule D4 customers be mitigated?

A. Eliminating this artifact, and the artifacts of other rate components that differ between Schedules D3 and D4 (e.g., distribution rate differences) can be accomplished simply by establishing a third TOU rate that is designed to be revenue neutral to Schedule D4 and that uses the accompanying Distribution and Distribution Surcharge rate designs that would otherwise apply to a D4 customer. In this way, all C/I customers would be presented with a choice of rates for the Power Supply rate component that are unaffected by other rate components and are not subject to time-differentiation or other structural differences. I will

[18] Exhibit A-16, Schedule F3 *Revised*, pp. 17 (Rate Schedule D3) & 23 (Rate Schedule D4).
[19] *Ibid*., p. 22.
[20] The impact of different Distribution rates and Distribution Surcharges would change the quoted percentage. For instance, inclusive of base Distribution charges, the average rate difference would increase from 0.61 cents/kWh to 0.93 cents/kWh, but the percentage increase would be lower at 6.6%.

refer to this rate as "MEIU Schedule D4.1" to differentiate it from the Company's proposed D3.11 and D14 rates.

Q. Have you developed a specific rate design for proposed MEIU Schedule D4.1?

A. Yes. As I previously noted, MEIU Schedule D4.1 would use the otherwise applicable Distribution and Distribution Surcharge structure for D4 and be differentiated only on the basis of Power Supply charges. My calculation of Power Supply charges is based on the 1-5 PM weekday on-peak window, which the Company proposed for Schedule D3.11 and which I recommend for use in all C/I TOU rates, applied to the D4 class load shape and D4 revenue requirement. Table 2 presents the specific Power Supply rates I propose for MEIU Schedule D4.1.

Table 2: Proposed MIEU D4.1 Power Supply Rates

Pricing Period	Power Supply Rate	Seasonal On-Peak Price Differential
Summer Peak	$0.12650	1.68
Summer Off-Peak	$0.07545	--
Winter Peak	$0.08073	1.07
Winter Off-Peak	$0.07545	--

B. ALL OF THE C/I TOU RATES SHOULD USE A COMMON 1-5 PM (M-F) ON-PEAK WINDOW

Q. Please describe the Company's proposals for establishing on-peak windows for its proposed C/I TOU rates.

A. DTE proposes to establish the on-peak pricing window for proposed Rate Schedule D3.11 at 1-5 PM, weekdays only. For proposed Rate Schedule D14, DTE proposes to set the on-peak window at 11 AM – 7 PM on weekday non-holidays.

Q. What is the Company's rationale for setting the D3.11 on-peak window to run from 1-5 PM on weekdays only?

A. With respect to proposed Schedule D3.11, DTE stated that the 1-5 PM weekday window encompasses 18 of the 20 monthly summer coincident peak hours from 2018 to 2022 (the last five years) and all 20 of the summer secondary voltage class peaks during the same time period.[21] DTE's proposed on-peak period for Schedule D14 is based on the on-peak period currently specified for Schedule D11, which serves as the base primary voltage rate schedule.[22]

Q. Do you agree with the Company's proposed delineation of on-peak periods for C/I TOU rates?

A. Not entirely. I agree that a 1-5 PM weekday on-peak window is reasonable, but that on-peak window should apply to all C/I TOU rate schedules, including proposed MEIU Schedule D4.1 and the Company's proposed Schedule D14.

Q. Please explain your recommendation that all C/I TOU rate schedules should use a 1-5 PM weekday on-peak window.

A. On-peak pricing windows under TOU rates should be: (a) of limited duration in order to provide an actionable price signal for load shifting, and (b) aligned with the time variation in the cost components (i.e., system peaks) that are intended to be incorporated within the TOU price signal. The four-hour on-peak window running from 1-5 PM that the Company

[21] Willis Direct, pp. 32–33.
[22] *Ibid*., p. 41.

has proposed for Schedule D3.11 meets these criteria. However, the 11 AM – 7 PM on-peak window for proposed Schedule D14 does not. It is too long (8 hours) to effectively promote load-shifting, and it encompasses a significant number of hours that are outside of the typical timing of system peak demands.

Q. Is it necessary to align on-peak TOU periods to the timing of non-coincident class peak demands, as opposed to coincident system peak demands?

A. No. The price signal incorporated within the C/I TOU rates is contained within the Power Supply component of the rates. Those Power Supply costs are caused in part by system-wide coincident peak ("CP") demands (and energy), as reflected in the cost of service allocators that use an energy-weighted Summer 4CP regime for production plant and 12CP regime for transmission expense.[23] As I previously noted, Witness Willis also referred to the importance of summer coincident peaks in explaining DTE's selection of a 1-5 PM on-peak period for proposed Schedule D3.11.[24] Non-coincident peak demands are relevant for distribution cost causation, but since the proposed TOU rate structure does not encompass distribution costs, the timing of non-coincident class demands should not influence the determination of appropriate TOU pricing periods. Accordingly, the correct frame of reference for the purpose of the C/I TOU rates in this case is the timing of coincident system peak demands, which the Company properly cited in support of its Schedule D3.11 proposal.

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[23] Direct Testimony of H.J. Maroun on behalf of DTE Electric Company, Case No. U-21534, p. 4.
[24] Willis Direct, pp. 32–33.

Q. Have you developed alternative proposed revenue-neutral rates based on a 1-5 PM on-peak period for use in the C/I TOU rates?

A. Yes. My calculation of rates based on a 1-5 PM weekday on-peak period for proposed MIEU Schedule D4.1 was previously shown in Table 2. Table 3 presents the rates that I have calculated for Schedule D14 with the substitution of a 1-5 PM weekdays on-peak window for the Company's proposed 11 AM – 7 PM weekday non-holiday on-peak window.

Table 3: Proposed D14 Power Supply Rates

Pricing Period	Power Supply Rate	Seasonal On-Peak Price Differential
Summer Peak	$0.11169	1.68
Summer Off-Peak	$0.06662	--
Winter Peak	$0.07128	1.07
Winter Off-Peak	$0.06662	--

Since the proposed Schedule D3.11 rates are based on this same on-peak window, they would remain the same as proposed by the Company, as corrected in DTE's revised exhibits filed July 19, 2024.[25]

C. DTE's Proposed Customer Enrollment Caps Should Be Eliminated

Q. Please restate the Company's proposed enrollment caps on the C/I TOU rates.

A. DTE proposes to limit enrollment on proposed Rate Schedule D3.11 (secondary voltage TOU) to 1,000 customers and enrollment on proposed Rate Schedule D14 (primary voltage TOU) to 50 MW of contract demand.

[25] *See* Exhibit A-16, Schedule F3 *Revised*, p. 22 of 58.

Q. Why does the Company propose to limit the availability of C/I TOU rates in this fashion?

A. DTE stated that its proposed enrollment cap for Rate Schedule D3.11 is intended to "account for potential unanticipated usage patterns on the rate."[26] For Rate Schedule D14 DTE characterized the enrollment cap as necessary until it can be evaluated as a separate rate class in its cost of service study due to the potential for an under-recovery of costs that would be allocated to other ratepayers in a future rate case.[27]

Q. How long would such enrollment limitations last?

A. The Company did not specify any specific term for the proposed enrollment caps in its testimony. In response to a discovery request regarding the permanence of such caps, DTE responded that the D3.11 cap is a "starting point" but did not explain in detail when it would consider proposing any change or elimination of the cap.[28] With respect to proposed Rate Schedule D14, DTE stated that the cap is intended to remain in place until the rate can be supported by its own cost of service study, at which point DTE would reevaluate the cap.[29]

[26] Willis Direct, p. 31.
[27] *Ibid*., p. 43
[28] Exhibit MEIU-23 (JRB-2).
[29] Exhibit MEIU-24 (JRB-3).

Q. Do you agree that customer elections to take service under the proposed C/I TOU rates should be constrained by enrollment caps?

A. No. The Company seems to be treating these rates as "pilots," which I disagree with for several reasons. First, any enrollment caps, especially those with uncertain durations, threaten to deprive DTE's customers of the ability to take advantage of the rates to reduce their own bills as well reduce rate class or system-wide costs in a manner that benefits other ratepayers. As long as a given rate schedule has a solid foundation in cost causation, there is no reason to limit participation. The lack of attractive C/I TOU rate options in DTE's service territory has long been a barrier to customers' ability to exercise greater control over their electricity bills. The introduction of such rates should not be accompanied by new constraints on their availability. At best, such limits introduce administrative inefficiency since their removal would require further litigation in future rate cases. At worst, they may further delay the availability of TOU rates to all customers that wish to participate.

Second, DTE's apparent concerns are both speculative and inconsistent. The proposed rates are designed to be revenue neutral relative to the broader groups of customers who would qualify for participation. Accordingly, any supposed risk of under-recovery rests on speculation rather than evidence, and such risk is not necessarily greater or lower than the risk of under-recovery present within the broader groups of customers and core rate schedules. Furthermore, the Company has already proposed to adjust the billing determinants for proposed Rate Schedule D3.11 to assume a certain amount of load-shifting from on-peak to off-peak time periods. The effect of this adjustment is to increase expected Company revenue relative to customer billings under the D3.11 rate schedule if the assumed amounts of load shifting are lower than what the Company has assumed.

Finally, the prospect of lower revenue is not by itself indicative of under-recovery of costs or unreasonable cost-shifting to other ratepayers. A TOU rate is intended to produce load shifting away from peak periods. This in turn produces cost savings that offset a revenue loss. In addition, the prospect of lower revenue from customers that save money on the rate without needing to shift their loads (i.e., structural savers with on-peak usage that is already below average) is a fully reasonable result, since those customers were previously overpaying at the otherwise applicable non-TOU rate relative to the costs they caused. In this context, the shifting of costs to other ratepayers is not unreasonable. Rather, it is the justified result of a rate structure that is more closely aligned with cost causation.

Q. Is there any historical precedent in Michigan for the deployment of C/I TOU rates without enrollment caps?

A. Yes. Consumers Energy has had uncapped C/I TOU rates available to its customers since 2017. Consumers Energy established its commercial secondary voltage TOU rate in January 2017 (Schedule GSTU) without any enrollment cap. As with DTE's proposed Schedule D3.11, Consumers Energy's Schedule GSTU was mapped to revenue neutrality with the existing small commercial rate schedule, albeit without the load-shifting billing determinant adjustments that DTE proposes.[30]

[30] See Application of Consumers Energy Company, Case No. U-18161, Filing No. U-18161-0001, p. 3.

Consumers Energy's primary voltage TOU rate (Schedule GPTU) was initially established in 2013 with a 50 MW enrollment cap. However, shortly thereafter in December 2014 Consumers Energy sought approval to double the cap to 100 MW due to customer interest, stating "When Rate GPTU was first implemented, the Company saw an overwhelming interest from customers. A lottery was held to determine which customers could take the rate, and there are customers on a waiting list today. The Company is proposing to expand the load from 50 MW to 100 MW in response to the customer interest."[31] At the time of this expansion, Schedule GPTU had not been in place long enough for it to be evaluated as a separate rate schedule in Consumers Energy's cost of service study so rates continued to be based on a revenue-neutral mapping to the broader primary voltage rate schedule.[32] The 100 MW cap on Schedule GPTU was then eliminated entirely in January 2017 concurrent with the establishment of Schedule GSTU.[33]

Q. What lessons can be learned from Consumers Energy's establishment of enrollment caps in the early versions of its primary voltage C/I TOU tariff?

A. The only outcomes of those caps were negative. They resulted in interested customers being wait-listed, delaying their enrollment, and regulatory inefficiencies associated with the need to first expand, and then remove, the caps in order to meet customer demand. The ultimate outcome of these successive proceedings was exactly the same as it would have been if the rate had not featured an availability cap in the first place. That is, at the end of the day, starting in January 2017 Consumers Energy offered an uncapped primary voltage

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[31] Direct Testimony of Laura M. Collins on behalf of Consumers Energy Company, Case No. U-17735, Filing No. U-17735-002, p. 17.
[32] *Ibid*., p. 16.
[33] December 20, 2016 Order of the Public Service Commission, Case No. U-18161, Filing No. U-18161-0004.

TOU tariff based on a revenue neutral mapping to the broader primary voltage rate schedule (i.e., rather than supported by its own cost of service analysis). DTE's proposal to wait until Schedule D14 can be evaluated as a separate cost of service class to eliminate enrollment restrictions seeks to emulate a failed aspect of Consumers Energy's roll-out of C/I TOU rates.

Q. Is there any further evidence that DTE's proposed enrollment caps could limit customer participation in practice?

A. Yes. Based on the cost of service study filed with its most recent rate case application, Consumers Energy's Schedule GSTU had enrollment of roughly 1,680 customers, equivalent to roughly 0.84% of secondary voltage commercial customers.[34] Even more strikingly, Consumers Energy Schedule GPTU had total enrollment of roughly 1,400 customers totaling more than 1,000 MW of maximum demand.[35] This level of interest in Consumers Energy's C/I TOU rates suggests that DTE's proposed enrollment limitations could in fact be far from sufficient to accommodate customer demand.

Q. Please summarize your recommendations on DTE's proposed enrollment caps on C/I TOU rates.

A. The proposed caps should be eliminated because they are unnecessary and could further delay the availability of TOU rates to all C/I customers that wish to enroll. I again point out that Consumers Energy has had uncapped C/I TOU rates available since 2017 and those rates have excited considerable customer interest. There is simply no compelling reason

[34] Case No. U-21585, Exhibit A-16 (LMC-7) Schedule F-3.0, pp. 5–6.
[35] *Ibid.*, pp. 14–16.

why DTE's C/I customers should be subjected to any further delays in the availability of TOU rate options.

D. THE C/I TOU RATES SHOULD BE MADE AVAILABLE WITHIN THREE (3) MONTHS

Q. Please restate DTE's proposal for making the proposed C/I TOU rates available to customers.

A. According to witness Willis, DTE intends to make the rates available by December 31, 2025, the end of the future test year.[36]

Q. How does the December 31, 2025 deadline compare to relevant regulatory milestones associated with the proposed C/I TOU rates?

A. The Company's proposed deployment deadline equates to an 11-month delay after the expected January 2025 Commission order in this case, and a delay of 25 months since the Commission's December 1, 2023 Order in Case No. U-21297 which required the Company to develop C/I TOU rates.

Q. How does DTE justify the proposed December 31, 2025 availability deadline?

A. In testimony, Company stated that after Commission approval, both rates "would need to be developed, tested, and implemented in the Company's billing system."[37] In response to discovery requesting further details on the development, testimony and implementation process, the Company did not provide any specific explanations of the associated

[36] Willis Direct, pp. 34 (Schedule D3.11) & 43 (Schedule D14).
[37] *Ibid.*

implementation needs and instead referred back to witness Willis' testimony on the general character and processes associated with its Information Technology ("IT") Annual Planning Cycle ("APC").[38] The Company also noted that a new residential TOU rate schedule (Schedule D1.13) approved in Case No. U-21297 was subject to a similar implementation deadline of the end of the projected test year in that case.[39]

Q. Please describe your understanding of the Company's IT APC and how it relates to DTE's proposed deployment timeline.

A. Witness Sharma describes the APC generally as representing "how the Company refines its investment strategies, establishes financial targets, and sanctions work," which it further states also applies to IT investments.[40] As witness Sharma describes it, a central aspect of this process is the use of a Project Prioritization Score ("PPS") that relies on various inputs intended to reflect alignment of investments with the Company's strategies and goals.[41] In other words, DTE describes this exercise as a "benefits analysis", stating "The result of this benefit analysis is a Project Prioritization Score (PPS)."[42] However, witness Sharma states that so-called "nondiscretionary Regulatory/Compliance… projects are considered "must-do" and therefore do not require a benefit analysis."[43]

Based on DTE's description of the APC, the takeaway theme is that it essentially revolves around executing DTE's priorities. As a consequence, the C/I TOU rates that DTE has

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[38] Exhibit MEIU-25 (JRB-4).
[39] Exhibit MEIU-26 (JRB-5).
[40] Direct Testimony of Pankaj Sharma on behalf of DTE Electric Company, Case No. U-21534, p. 6.
[41] *Ibid.*, p. 7.
[42] *Ibid.*, p. 8.
[43] *Ibid.*

historically opposed offering will fall towards the bottom of the prioritization spectrum unless the Commission requires otherwise. The December 31, 2025 deployment timeline, a 25-month delay since the Commission directed DTE to develop C/I TOU rates, is a reflection of DTE's priorities, not any identified technical challenges.

Q. How are the circumstances governing the deployment of recently adopted Schedule D1.13 distinguishable from those present for the C/I TOU rates?

A. Schedule D1.13 is a residential TOU rate schedule and, at the time it was adopted, residential customers already possessed multiple alternative TOU options. By contrast, C/I customers lack viable TOU rate options, a situation that has persisted for years even after the completion of advanced metering infrastructure ("AMI") deployment established the basic technological foundation for broad TOU rate availability. This difference in circumstances warrants a higher degree of urgency for the deployment of C/I TOU rates than that present for refinements to residential TOU rate option.

Q. Has the Company previously sought deployment of TOU rates on a more accelerated schedule?

A. Yes. In its Application seeking approval of the Advanced Customer Pricing Pilot ("ACPP") applicable to residential customers, the Company requested and received approval to implement the ACPP rates within six (6) months of a Commission order. [44] The Company requested this six-month deployment timeline despite that fact that the ACPP involved the

[44] See Application of DTE Electric Company, Case No. U-20602, Filing No. U-20602, p. 2; see also September 26, 2019 Order of the Public Service Commission ("U-20602 Order"), Case No. U-20602, Filing No. U-20602-0015, p. 4.

additional complexities of a rate-testing pilot involving a total of six (6) distinct rates differentiated into three (3) significantly different rate structures (two rates for each structure).[45]

Q. Has the Company identified any specific barriers or complexities associated with the proposed C/I TOU rates that differ from the ACPP rates?

A. No. When asked to do so in a discovery request, the Company stated that it could not compare the implementation of ACPP rates to the C/I TOU rates and again referred back to its general IT APC cycle.[46]

Q. What were the deployment timelines associated with the implementation of C/I TOU rates in Consumers Energy's service territory?

A. Consumers Energy's secondary voltage commercial TOU rate (Schedule GSTU) was made available in January 2017 based on an Application submitted on August 1, 2016 and the Commission's order approving the rate on December 20, 2016.[47] Thus, it was implemented within one (1) month of Commission approval and within five (5) months of when it was submitted for Commission review. Consumers Energy's primary voltage TOU rate (Schedule GPTU) was initially approved in a May 15, 2013 Commission order,[48] and the original tariff sheet took effect for the July 2013 billing month, roughly one (1) month after that.[49]

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[45] See U-20602 Order, p. 2.
[46] Exhibit MEIU-27 (JRB-6).
[47] December 20, 2016 Order of the Public Service Commission, Case No. U-18161, Filing No. U-18161-0004.
[48] See May 15, 2013 Order of the Public Service Commission, Case No. U-17087, Filing No. U-17087-0300.
[49] *See* Original Sheet No. D-36.10. p. 798 (pin-cite). https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/consumer/rate-books/electric/consumers/consumers-retired/consumers13candthroughendofd.pdf

Q. Given the context provided in the preceding discussion, how do you respond to DTE's proposed implementation schedule for the C/I TOU rates?

A. DTE's proposed implementation timeline amounts to an unjustified delay in the availability of these rates which can only reasonably be explained by the fact that the Company opposed the development of these rates and now chooses to de-prioritize their implementation to greatest degree that it can (thinly) attempt to justify. I reach that conclusion based on the following <u>facts</u>:

- The Company has been on notice since December 2023 that the Commission wished it to develop C/I TOU rates. At the time of a Commission order in this case (January 2025), DTE will have had approximately 14 months to prepare for their implementation.
- DTE already has considerable experience in implementing residential TOU rates with similar designs to the proposed C/I TOU rates, as well as considerably more complex demand response oriented TOU rates (i.e., critical peak pricing rates), and it has failed to offer any explanation as to why the proposed C/I TOU rates involve additional billing system complexities or other complicating factors.
- In 2019, at a time when it had less experience with TOU rate implementation, the Company sought and received approval for the significantly more complex ACPP under a six-month implementation timeline.
- Consumers Energy was able to accomplish deployment of its C/I TOU rates within a month of a Commission order approving those rates, and a maximum of five (5) months from the date they were initially proposed.

There are simply no technical or policy reasons that merit the deployment delay that DTE proposes.

Q. What is your recommendation for the timeline for making the C/I TOU rates available to customers?

A. I recommend that the Commission direct DTE to make all of the rates available within a maximum of three (3) months from the date of a Commission order in this case. Given that DTE's billing system is clearly capable of accommodating existing rates with an identical structure, even this short delay seems likely to be longer than is technically necessary to accomplish billing system updates.

IV. PROVISION OF RATE COMPARISON REPORTS

Q. Please explain why it is important that DTE's rollout of C/I TOU rates be accompanied by the development of a rate comparison tool and report.

A. Without such a tool it will be highly difficult for customers to make informed decisions on whether to enroll on a TOU rate since each customer would essentially have to build their own model to conduct such a comparison. The creation of a standardized "report" from such a tool is a critical element for two reasons. First, it makes the details of the results of the comparison transparent, which supports customer confidence in and acceptance of those results. Second, it is necessary in order to allow customers to be able to understand precisely how the characteristics of their usage influence their bills under different rate designs, which is a fundamental necessity for considering the opportunities for load-shifting that produces cost savings.

Q. What level of assistance does DTE currently provide to customers seeking to identify the least costly rate for them?

A. The Company's tariff states "If requested, the Company will advise the customer in the selection of the rate which will give him the lowest cost of service, based on the information at hand, but the responsibility for the selection of the rate lies with the customer."[50] In response to a discovery request, DTE explained that this assistance is supported by customer service representatives who are trained to analyze the customer's account and use Bill Simulator and Bill Analyzer tools to simulate the impacts of different rates.[51] However, the Bill Simulator tool cannot model non-residential rates.[52] Consequently, it is not clear how a customer service representative would be able to effectively advise a C/I customer on which rate option would give them the "lowest cost of service."

Q. Would the Company's current Bill Simulator tool be adequate for facilitating C/I customer consideration of TOU rate enrollment if it were modified to incorporate C/I rates?

A. No. The outputs from the bill simulation are confined to single numbers representing a customer's a 12-month bill and 1-month bill under a given rate, shown in Figures 1 and 2 below.[53]

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[50] DTE Electric Tariff, Section C4.4 – Choice of Rates.
[51] Exhibit MEIU-28 (JRB-7).
[52] Exhibit MEIU-29 (JRB-8).
[53] Exhibit MEIU-30 (JRB-9).

Figure 1: Annual Bill Simulation Results Screenshot

Artifact to see the results for 12 months:

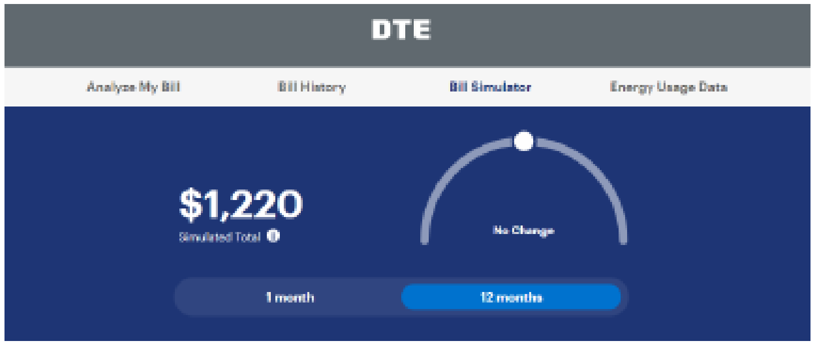
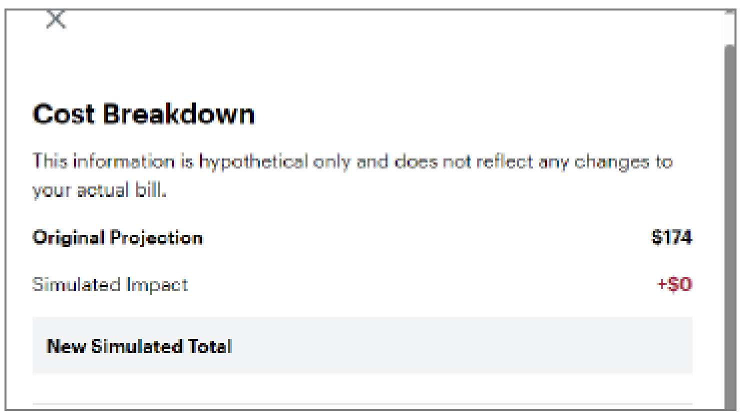


Figure 2: Monthly Bill Simulation Results Screenshot

Artifact to see the results for one month:



This level of information, while not useless, is clearly insufficient to facilitate true customer understanding of a key aspect of rate selection, which is the reason(s) why a given rate is more or less expensive than another option. In other words, if a customer cannot understand the why, they cannot readily identify the how (i.e., what are their opportunities for reducing costs under one rate as compared to the opportunities for doing so on another rate?).

Q. What details of the bill simulation should be made available in these rate comparison reports?

A. The rate comparison reports should show: (a) the customer's billing determinants, the applicable rates for each charge (including distribution and riders), and the total monthly charges under each rate schedule within the comparison for a 12-month period; and (b) a summation of the monthly charges over a 12-month period. The rate schedules included in each report should reflect all of main rate schedules for which a customer is eligible. For instance, a secondary voltage customer should see results for four (4) Rate Schedules: D3, D3.11, D4, and MIEU D4.1. Primary voltage customers should see results for Rate Schedules D11 and D14. Exhibit MEIU-31 (JRB-10) presents an illustrative example of how a rate comparison report based on these parameters could look in practice.

Q. When should such rate comparison reports be made available to DTE's customers?

A. The rate comparison reports should be made available as soon as possible upon the availability of the C/I TOU rate options, which I have recommended should be implemented within three (3) months of a Commission order in this case. A three-month window should allow DTE ample time to develop the associated tool. In practice, the bill calculation itself is not particularly complex. A person with adequate competency in Excel could build a spreadsheet-based model with all of the necessary calculation logic in a single afternoon. The remaining technical aspect of such a tool, i.e., pulling in historic customer usage data, has already been developed for the current Bill Simulator tool and can simply be replicated.

V. SUMMARIZED RECOMMENDATIONS & CONCLUSION

Q. Please summarize your recommendations to the Commission.

A. I recommend that the Commission approve the establishment of C/I TOU rates with the following modifications:

1. The C/I TOU rates should consist of three (3) individual rate schedules that reflect rates mapped to revenue neutrality with the existing D3, D4, and D11 Rate Schedules, modifying the Company's proposal by creating a TOU corollary for Rate Schedule D4 in addition to those proposed for Rate Schedules D3 and D11.
2. The C/I TOU rates should use a common on-peak pricing window of 1-5 PM, weekdays only, which has the effect of modifying the 11 AM – 7 PM non-holiday weekdays on-peak window that the Company proposed for Rate Schedule D14.
3. The Company's proposed enrollment limitations (i.e., caps) on the individual proposed C/I TOU rate schedules should be eliminated in their entirety.
4. The C/I TOU rates should be made available for customer enrollment within three (3) months of the Commission's final order in this case.
5. DTE should be directed to develop a rate comparison tool that can model C/I rates and that produces a standardized report as an output and make such reports available by the time the new C/I TOU rates are made available.

Q. Does this conclude your testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the Application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	))))))	Case No. U-21534

PROOF OF SERVICE

COMMONWEALTH OF VIRGINIA)
) ss.
COUNTY OF PRINCE WILLIAM)

Keri D. Click, the undersigned, being first duly sworn, deposes and says that she is a Paralegal at Potomac Law Group PLLC and that on the 26th day of July, 2024 she served a copy of the Public Redacted Direct Testimony of Dr. Laura S. Sherman and Direct Testimony of Justin R. Barnes on behalf of Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Advanced Energy United, via email, upon those individuals listed on the attached Service List.

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