STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of DTE Electric Company 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 Volume No. 6 PUBLIC RECORD

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CROSS-EXAMINATION - PART 2 - REVISED

(Continues following Page 3183 of Part 1.)

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MR. ABRAMS: Good morning, your Honor.

COURT REPORTER: Oh, bad connection. Try again.

MR. ABRAMS: O.K. How about now?

COURT REPORTER: There you go. Thank you.

MR. ABRAMS: I'll speak close to the microphone. At this time, on behalf of the Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar, who I will refer to as the Clean Energy Organizations, and by stipulation of the parties, I move to bind in the Direct Testimony of William D. Kenworthy, consisting of a cover page, a table of contents, and 22 pages of questions and answers, and I'd move for the admission of Exhibits CEO-1 through CEO-3. I also move to bind in the Rebuttal Testimony of William D. Kenworthy, consisting of a cover page, a table of contents, and 21 pages of questions and answers.

JUDGE WALLACE: Is there any objection to binding in the direct and rebuttal testimony of Mr. Kenworthy?

Hearing none, the testimony is bound in.

Is there any objection to the admission

of Exhibits CEO-1 through CEO 3?

Hearing none, those exhibits are admitted.

(Testimony bound in.)

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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

DIRECT TESTIMONY OF

WILLIAM D. KENWORTHY

ON BEHALF OF

THE ECOLOGY CENTER, THE ENVIRONMENTAL LAW & POLICY CENTER, UNION OF CONCERNED SCIENTISTS, AND VOTE SOLAR

July 26, 2024

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I. INTRODUCTION AND SUMMARY

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is William D. Kenworthy (he/him). My business address is 1 South Dearborn Street, 20th Floor, Chicago, Illinois 60603.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I serve as Regulatory Director, Midwest for Vote Solar. I oversee policy development and implementation related to large scale and distributed solar generation in the region. I also review regulatory filings, perform technical analyses, and testify in commission proceedings on issues relating to solar generation.

Vote Solar is an independent 501(c)(3) nonprofit working to repower the U.S. with clean energy by making solar power more accessible and affordable through effective policy advocacy. Vote Solar seeks to promote the development of solar at every scale, from distributed rooftop solar to large utility-scale plants. Vote Solar has over 90,000 members nationally, including over 2,700 members in Michigan. Vote Solar is not a trade organization nor does it have corporate members.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS DIRECT TESTIMONY?

A. I appear here in my capacity as an expert witness on behalf of the Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar. I refer to these parties collectively in this case as the Clean Energy Organizations or "CEO."

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS, EXPERIENCE, AND EDUCATION.

A. I have nearly 30 years of experience in the energy industry in both the public and private sectors working in the renewable energy business and in energy policy. In my role as Senior Regulatory Director of Vote Solar since 2018, I have provided expert witness testimony in

dozens of proceedings (see below) related to grid modernization, distributed energy resources, and energy equity. Prior to joining Vote Solar, I spent eight years in solar energy project development working primarily on commercial and industrial distributed solar projects in the Midwest.

I received a Master of Public & Private Management degree from the Yale University School of Management with a concentration in Regulation and Competitive Strategy. My research in graduate school focused on regulatory theory and practice. I also have a Bachelor of Science in Foreign Service from Georgetown University. A copy of my resume is attached as Exhibit CEO-1.

Q. HAVE YOU TESTIFIED BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION PREVIOUSLY?

A. Yes. I provided testimony in the following proceedings before the MPSC:

- U-20162 – DTE Electric Co. Electric Rate Case
- U-20359 – Indiana Michigan Power Co. Electric Rate Case
- U-20471 – DTE Electric Co. Integrated Resource Plan
- U-20561 – DTE Electric Co. Electric Rate Case
- U-20697 – Consumers Energy Co. Electric Rate Case
- U-20649 – Consumers Energy Co. Voluntary Green Pricing Case
- U-20713/U-20851 – DTE Electric Co. Consolidated Voluntary Green Pricing and Renewable Energy Plan Amendment cases
- U-21090 – Consumers Energy Co. Integrated Resource Plan
- U-21134 – Consumers Energy Co. Voluntary Green Pricing Case
- U-21224 – Consumers Energy Co. Electric Rate Case

- U-21389 – Consumers Energy Co. Electric Rate Case
- U-20836 – DTE Electric Co. Electric Rate Case
- U-21172 – DTE Electric Voluntary Green Pricing Case
- U-21193 - DTE Electric Integrated Resource Plan
- U-21297 - DTE Electric Co. Electric Rate Case

Q: HAVE YOU TESTIFIED OR PROVIDED COMMENTS IN SIMILAR STATE REGULATORY PROCEEDINGS?

A: Yes. I have provided testimony in rate cases before the Iowa Utilities Board and the Public Service Commission of Wisconsin. I have provided testimony on community solar services, the value of distributed energy resources, and the calculation of distributed generation penetration before the Illinois Commerce Commission and the Indiana Utility Regulatory Commission. I have provided comments in numerous other proceedings before the Illinois Commerce Commission, the Illinois Power Agency, the Minnesota Public Utility Commission, and the Public Service Commission of Wisconsin. A list of testimony and comments that I have filed is included as Exhibit CEO-2.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring the following exhibits:

- Exhibit CEO-1: Resume of William D. Kenworthy
- Exhibit CEO-2: Testimony and Comments of William D. Kenworthy
- Exhibit CEO-3: Klass Alexandra B. and Chan, Gabriel, Regulating for Energy Justice (February 11, 2022). 97 NYU Law Review 1426 (2022).

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: My testimony provides context for the importance of distribution planning, including rigorous cost-benefit analysis, to support utility investment and cost recovery proposals in rate cases. I also describe the importance of embedding principles of equity and energy justice into the Company's capital investment plans.

Q: WHO ARE THE OTHER WITNESSES APPEARING ON BEHALF OF THE CLEAN ENERGY ORGANIZATIONS?

A: In addition to myself, the CEO offer testimony of two other expert witnesses who will provide insights and recommendations regarding DTE's rate case proposal.

- **Curt Volkmann** – a grid engineer with over 40 years of experience in the utility industry. In his testimony, Witness Volkmann provides an assessment of DTE's rate case application as it relates to distribution planning and the transformation of the Company's distribution system.
- **Boratha Tan** – a regulatory manager at Vote Solar. In his testimony, Witness Tan provides an overview of the CEO engagement with the Company regarding regression analyses related to reliability and several population demographics.

II. <u>THE IMPORTANT ROLE OF DISTRIBUTION SYSTEM PLANNING AND ENERGY JUSTICE IN ELECTRIC UTILITY RATE CASES.</u>

Q: PLEASE EXPLAIN THE FOCUS OF THE CLEAN ENERGY ORGANIZATIONS (CEO) IN THIS RATE CASE?

A: The Clean Energy Organizations are dedicated to ensuring that DTE Electric Company establishes a set of comprehensive processes related to distribution planning and spending that ensure that the Company's long-term distribution system strategy is properly vetted and delivers customers reasonable, prudent, and equitable service. This involves conducting thorough cost-effectiveness analyses that appropriately incorporate equity and

environmental justice considerations. To achieve these goals, the CEO aim to ensure that DTE prepares the grid for the inevitable and desirable shift toward electrification and distributed energy resources (DERs). These trends will benefit customers by reducing household energy burden and enabling a more efficient, cost-effective, and equitable grid. And they will support the state's clean energy goals by reducing greenhouse gas emissions and improving air quality.

Q: WHAT KIND OF INVESTMENTS ARE NECESSARY TO PREPARE THE GRID FOR ELECTRIFICATION?

A: Preparing the grid for electrification requires several types of investments. These include upgrading infrastructure to handle increased load, integrating advanced technologies to enhance grid management and reliability, and ensuring sufficient capacity to accommodate new electric devices and systems. The CEO acknowledge the need for DTE to recover prudent and cost-effective investments in the electric distribution system to improve power reliability and support clean energy goals. Such investments are critical to ensuring that the grid can support the increased demand from electrification and deliver the associated benefits to customers.

Q: WHY IS IT IMPORTANT FOR DTE TO CONDUCT THOROUGH COST-EFFECTIVENESS ANALYSES?

A: In its most recent distribution grid plan (DGP), DTE estimated that it will need to spend approximately $9 billion over the next five years and over $25 billion over the next decade to modernize its distribution system.[1] The magnitude of this projected spending highlights the vital role of rigorous cost-benefit analysis to ensure these investments are justified and

[1] DTE Ex. A-23 Sch. M-8, DTE 2023 Distribution Grid Plan at 55, 119, 121.

will provide the maximum benefit to customers. Focusing on cost-effectiveness can also help promote equity by ensuring that utility investments are beneficial for those most sensitive to energy burdens and costs.

Q: HOW HAS THE COMMISSION DESCRIBED THE RELEVANCE OF DTE'S DISTRIBUTION GRID PLAN TO THE COMMISSION'S REVIEW OF RATE CASES?

A: In DTE's last rate case (U-21297), the Commission stated that it intends to weigh and evaluate the credibility of DTE's distribution grid plan (DGP) and global prioritization model (GPM)[2] in future rate cases "to determine whether it supports the spending proposed by the company and whether it is reasonable and prudent to pass those costs on to ratepayers."[3] The Commission emphasized the need for greater transparency to "provide intervenors and the Commission with a full understanding of how [] projects were selected and why they were selected."[4]

Q: HOW HAS DTE RESPONDED TO THE COMMISSION'S ORDERS REGARDING DISTRIBUTION PLANNING IN THIS RATE CASE?

A: As discussed in more detail by CEO Witness Volkmann, the Company has provided increased transparency into the inner workings of the GPM, providing CEO more insight into the mechanics of the model through discovery.[5] The Company has also begun to roll out cost-effectiveness analyses for some of its larger capital investment programs including the pole top maintenance and modernization program (PTMM) and strategic

[2] The GPM is a tool that DTE developed to prioritize investments by ranking projects and programs based on the benefits the Company expects the project or program to deliver. The GPM does not evaluate the expected costs of a project against its benefits and is therefore *not* a cost-benefit analysis. AJK-54.
3 Case No. U-21297, Final order at 70-71 (Dec. 1, 2023).
4 Case No. U-21297, Final Order at 72 (Dec. 1, 2023).
[5] *See* Direct Testimony of CEO Witness Curt Volkmann at 6-8.

undergrounding.[6] The CEO view these actions as positive incremental steps forward in the Company's path towards standardized, repeatable processes, that ensure cost-effective, strategic management and operation of the distribution system.

III. EQUITY AND ENVIRONMENTAL JUSTICE

Q: HOW DOES DTE ELECTRIC DEFINE ENVIRONMENTAL JUSTICE (EJ)?

A: Witness Kryscynski explains that DTE Electric defines environmental justice based on the State of Michigan's definition, which is "the equitable treatment and meaningful involvement of all people, regardless of race, color, national origin, ability, or income in the development and application of laws, regulations, and policies that affect the environment, as well as the places people live, work, play, worship, and learn."[7]

Q: HOW SHOULD EQUITY AND ENVIRONMENTAL JUSTICE FACTOR INTO THE COMMISSION'S REVIEW OF THIS RATE CASE?

A: Energy justice relates to many areas of the Commission's jurisdiction including ratemaking, resource planning and distribution system planning. The policy basis for pursuing energy justice flows from the Commission's obligation to approve "just and reasonable" rates.[8] In a recent article published in the NYU Law Review entitled "Regulating for Energy Justice," Professors Alexandra Klass and Gabe Chan argue "rate setting is and always has been social policy implemented within a legislative framework designed to promote the public interest."[9] Professors Klass and Chan explain that energy justice is therefore just part of what constitutes "just and reasonable rates."[10]

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[6] *See* DTE Ex. A-23, Sch. M-13 at 5.
[7] AJK-78.
[8] MCL 460.557(4).
[9] Klass Alexandra B. and Chan, Gabriel, *Regulating for Energy Justice* (February 11, 2022). 97 NYU Law Review 1426 (2022). A copy of this article is attached as Ex. CEO-3.
[10] *Id.*

The foundational principles of equity and environmental justice provide regulators with the authority and, arguably, the duty to ensure that all members of the public enjoy equitable access to utility products and services and protection from harm on just and reasonable terms. By prioritizing these considerations, DTE can help reduce disparities in service quality and reliability, ensuring a fair distribution of the benefits of grid investments.

Q: WHY IS IMPORTANT TO CONSIDER PRINCIPLES OF EQUITY AND ENVIRONMENTAL JUSTICE IN RATE CASES?

A: As Professors Klass and Chan state in their article, "low-income and marginalized residential customers have not historically had the regulatory and technical sophistication to navigate regulatory rate-setting processes . . . [a]nd therefore, there is a historic backlog of decisions never considered that have put low-income residential customers at a disadvantage."[11]

Q: PLEASE SUMMARIZE THE COMMISSION'S DIRECTIVES REGARDING ENVIRONMENTAL JUSTICE IN DTE'S LAST RATE CASE ORDER.

A: The Commission made several important statements regarding environmental justice in the last rate case (U-21297). First, and most fundamentally, the Commission emphasized the need for DTE Electric to include environmental justice and equity considerations in the distribution planning process. This must include, at a minimum, "EJ analyses that provide information in community vulnerability gradations based on the MiEJScreen composite score for the circuits."[12] Additionally, the Commission stated that it "continues to seek results from ongoing equity analyses from the company that demonstrate how it balances

[11] Ex. CEO-3 at 1481.
[12] Case No. U-21297, Final Order at 111-112 (Dec. 1, 2023).

its spending such that it does not disproportionately skew benefits away from more vulnerable or disadvantaged communities."[13]

With one minor adjustment on the use of regression, discussed below, the Commission adopted the following Staff recommendations:

1. A requirement for future environmental analyses to provide community vulnerability gradation information based on the MiEJScreen composite score, and define vulnerable communities based on the threshold of the MiEJScreen composite score for environmental justice analyses.
2. A requirement to provide Customers Experiencing Multiple Interruptions data for customers who experience six or more sustained interruptions per year by zip code and census tract with GeoID number moving forward and for five years prior to the rate case or distribution plan.
3. A requirement to promptly address known public safety hazards.
4. A requirement to report third-party contacts under R 460.38041 along with the third party's health status and contact description to include contact location, distribution system voltage, whether a wire was down, and whether it involved an arc or distribution wire.
5. A requirement for greater transparency for projects, programs, and deployment locations in future rate cases.
6. A requirement to include climate resiliency in future distribution plans.
7. A requirement to develop a clear, repeatable process for interested parties to obtain and use GIS data for their own analyses.

[13] *Id.*

8. A requirement to engage interested and affected customers and communities in stakeholder meetings.[14]

Q: WHAT IS THE MIEJSCREEN TOOL, AND HOW DID THE COMMISSION EXPECT DTE ELECTRIC TO USE IT?

A: The MiEJScreen tool is a mapping and screening tool developed by the Michigan Department of Environment, Great Lakes, and Energy (EGLE).[15] It combines environmental conditions and population characteristics to highlight the most vulnerable communities in Michigan by census tract.[16] As mentioned above, the Commission directed DTE Electric to use this tool to conduct an analysis of distribution-related environmental justice. The analysis aims to identify the communities most impacted by environmental and energy-related issues and to develop plans to improve reliability and address the specific needs of these communities.[17]

Q: WHAT SPECIFIC STEPS DID THE COMMISSION ORDER WITH REGARD TO MAPPING AND PRESENTING DATA IN VISUAL FORMATS?

A: In adopting the Staff recommendation cited above, the Commission ordered DTE to provide future analyses that I recommend should include visualizations of reliability and other utility performance characteristics that can aide in utility planning, inform Commission evaluation of investment plans, and educate customers and other stakeholders on progress toward the utility achieving its goals.

Q: HAS DTE COMPLIED WITH THE COMMISSION ORDER WITH REGARD TO MAPPING AND PRESENTING DATA IN VISUAL FORMATS?

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[14] *Id.* at 351.
[15] AJK-78.
[16] *Id.*
[17] Case No. U-21297, Final Order at 351 (Dec. 1, 2023).

A: The Company appears to be using the mapping tools to evaluate reliability data by census tract. CEO are pleased to see DTE using the maps for this purpose.

Q: ARE THERE OTHER WAYS THE MAPPING TOOL COULD BE USEFUL FOR DTE?

A: Yes. Just as DTE appears to be using the mapping tool to evaluate reliability data, mapping can provide granular, geographic-specific information regarding other aspects of DTE's system and the customer experience. For example, a mapping tool can be used to identify geographic areas where there are: high concentrations of poverty, high concentrations of people of color, higher levels of pollutions, and parts of the system which may be older than other areas. DTE has an obligation to serve all of its customers, and part of that obligation requires it to serve all customers equitably. By identifying geographic areas that may be under-served in terms of reliability, capital investment and/or programs, DTE can better target investment, operations, and programming to these under-served areas, thereby meeting its obligation to provide service equitably.

Likewise, the Company should expand the scope of equity analysis beyond reliability to include other dimensions of utility service quality. One important dimension of utility service that I have previously testified on in previous DTE rate case is grid access. Grid accept is a dimension of utility performance that is roughly measured by hosting capacity but also some understanding of how much of what kind (generation or load) of capacity is appropriate for individual customers and communities. A critical component of an equitable system is equal access to the grid.

Q: WHY IS IT IMPORTANT TO IDENTIFY AREAS WITH HIGH CONCENTRATIONS OF POVERTY AND/OR HIGH CONCENTRATIONS OF PEOPLE OF COLOR?

A: To effectively reach communities with high concentrations of poverty and/or people of color, DTE may have to engage with its customers in these areas in a different way than it engages with its other customers. By identifying geographic areas with high concentrations of poverty and/or people of color, DTE can better understand how to be more culturally responsive to the challenges faced by these customers.

Q: HOW ELSE CAN DTE USE MIEJSCREEN TO INFORM ITS PROGRAMMATIC AND CAPITAL DECISION MAKING?

A: DTE can use MiEJScreen to inform the design and implementation of its customer programs and policies going forward. Customer programs and policies include the Company's energy efficiency and demand response programs, low-income energy efficiency and assistance programs, arrearage management programs, and residential disconnection policy.

Q: HOW CAN AN INTERACTIVE MAPPING TOOL HELP DTE INFORM THE DESIGN AND IMPLEMENTATION OF ITS CUSTOMER PROGRAM, POLICIES, AND INVESTMENTS?

A: The mapping tool can help to provide information on a program's effectiveness by geography. For example, there may be certain geographic areas where energy efficiency and/or energy assistance uptake is very low. By identifying those geographic areas, DTE can better understand where to target its spending on improving energy efficiency or energy assistance uptake.

Q: ARE THERE SPECIFIC INDICATORS AND METRICS THE COMPANY SHOULD BE USING IN ITS PROGRAM AND CAPITAL INVESTMENTS DECISION MAKING?

A: Yes. The MiEJScreen tool includes several socioeconomic indicators including low income populations, Black, Indigenous, People of Color (BIPOC) Populations, and

Housing Burden.[18] There are several indicators that are relevant to electric utilities that are not being measured in the state's tool. I recommend that the Company measure several other indicators at the most granular level, census block. I recommend the Company begin tracking:

- The **average energy burden of residential customers** measured at the census block. This indicator is calculated by dividing the average annual residential bill by the average area median income by census block. Many of DTE's customers experience high energy burden and these customers are distributed unevenly across DTE's territory.[19] Calculating energy burden at the census block group level will provide better insight as to where high energy burdened customers are located, and allow the Company to better target those areas for energy assistance.
- The **percentage of residential customers disconnected per census block**. This indicator is calculated as the number of disconnected premises in a census block divided by the total number of electric premises in the same census block.
- The **percentage of low-income residential customers that participated in one or more energy assistance programs** in a year, measured at the census block level. This indicator is calculated as the number of low-income households who participated in one or more energy assistance programs in a year divided by the total number of low-income households in the same census block. If the Company

[18] The MiEJScreen socioeconomic indicators are Low Income Population, Black, Indigenous, People of Color Population, Education Attainment, Linguistic Isolation, Population Under Age 5, Population Over Age 64, Unemployment, and Housing Burden.

[19] *See also* discussion of energy burden in Case No. U-21193, Direct Testimony of Boris Lukanov (Mar. 9, 2023). In 2023, CEO Witness Lukanov estimated that the total energy burden in DTE's territory was $800 million, with low- and moderate-income households bearing $650 million of that burden. *Id.* at 18.

does not know the number of low-income households in a census block, the utility should develop a stakeholder reviewed reasonable estimate.

- The **percentage of low-income residential customers that participated in a payment plan** in a year, measured at the census block level. This indicator is calculated as the number of low-income households who participated in a payment plan in a year divided by the total number of low-income households in the same census block. If the Company does not know the number of low-income households in a census block, the utility should develop a stakeholder-reviewed reasonable estimate.
- The **percentage of low-income residential customers that participated in the Company's energy efficiency program** in a year, measured at the census block level. This indicator is calculated as the number of low-income households who participated in an energy efficiency program divided by the total number of low-income households in the same census block. If the Company does not know the number of low-income households in a census block, the utility should develop a stakeholder-reviewed reasonable estimate.

Q: WHY DO YOU RECOMMEND CALCULATING THESE INDICATORS?

A: Calculating and then analyzing these indicators at the census block level can help the utility, Commission, stakeholders, and policymakers identify where there may be discrepancies in the system and can help inform planning and investment decisions to better serve low-income communities and communities with high BIPOC populations.

Q: THE MIEJSCREEN TOOL MEASURES INDICATORS AT THE CENSUS TRACT LEVEL. YOU RECOMMEND MEASURING THE ADDITIONAL INDICATORS AT THE CENSUS BLOCK GROUP LEVEL. WHAT IS THE

VALUE OF THE MORE GRANULAR MEASUREMENT TO DTE AND THE COMMISSION?

A: In previous testimony in DTE's 2022 rate case, I recommended that the census block group as the appropriate level of granularity for analyzing this type of data.[20] Evaluating the Company's service at the census block groups level allows the Company to be more precise when it considers program and investment level decisions. However, I understand the need to balance using the best information with minimizing administrative burden. To start, I recommend the Company use the existing MiEJScreen tool as it develops its own internal processes for using this type of mapping tool for planning, developing, and implementing programs and investments. At a later date, the Company may need to either work with the state to update the MiEJScreen tool to go to the census block level or develop its own mapping tool similar to the mapping tool that Xcel Energy in Minnesota developed. In the meantime, the census block group level information can still be used as available additional information considered with the MiEJScreen tool that is available for refining Company decision-making.

Q: ARE YOU AWARE OF ANY OTHER STATES THAT USE A SIMILAR MAPPING TOOL?

A: Yes, I am aware of at least three other states: Minnesota,[21] Washington state,[22] and California.[23] Nationally, the U.S. Center for Disease Control maintains a national

[20] Case No. U-20836, Direct Testimony of CEO Witness William Kenworthy at 18-19 (May 19, 2022).
[21] Minnesota Department of Health, Minnesota Public Heat Data Access. Available at: https://data.web.health.state.mn.us/equity_metadata
[22] Washington State Department of Health, Washington Environmental Health Disparities Map. Available at: https://doh.wa.gov/data-and-statistical-reports/washington-tracking-network-wtn/washington-environmentalhealth-disparities-map
[23] Washington State Department of Health, Washington Environmental Health Disparities Map. Available at: https://doh.wa.gov/data-and-statistical-reports/washington-tracking-network-wtn/washington-environmentalhealth-disparities-map

Environmental Justice Index which measures 36 social vulnerability, environmental, and health indicators for measuring cumulative environmental burden in communities. The CDC's tool allows users to explore the indicators by census tract across the state of Michigan. In Minnesota, Xcel Energy, a dual-fuel utility like DTE, created its own interactive map of its electric and gas service territories. Xcel Energy's electric division tracks many of the same indicators I recommend DTE track and combine that data with demographic data from the US Census Bureau.

Q: HOW DO THE MINNESOTA PUBLIC UTILITIES COMMISSION AND XCEL USE THE INTERACTIVE MAPPING TOOL?

A: The mapping tool is starting to be used by the Minnesota Public Utilities Commission, Xcel Energy, and stakeholders to design and implement programs. First, Xcel Energy's mapping tool shows that energy assistance uptake in certain geographic areas is relatively low and Xcel is using this information to direct energy assistance to those areas. Furthermore, in Xcel Energy's last rate case, interested parties used the mapping tool to posit that electric reliability is lower for communities of color and electric disconnections are higher, even when controlling for income. As a result, Xcel Energy evaluated that hypothesis and published results in March 2024, which confirmed there were some disparities in reliability and disconnections in certain areas with high concentrations of communities of color. The MPUC and stakeholders are now in the process of determining whether and how to address these disparities. Second, after extensive work with the Company's Equity Stakeholder Advisory Group, Xcel Energy recently unveiled a two-year pilot that would provide automatic bill credits for customers in certain low-income areas. The Company and the stakeholder group utilized the mapping tool to identify the census block groups with the highest energy burdens and proposed to provide an automatic bill credit to all households

in high-energy burdened census block groups. If approved, the automatic credit will bring the median energy burden in all census block groups in Xcel Energy's service territory down to 4%; the bill credit will go to approximately 23,000 households in 77 census block groups. The automatic credit occurs without active enrollment from the household, eliminating the need for customers with high energy burdens to apply for energy assistance. The pilot petition is currently pending before the Minnesota Public Utilities Commission and a decision is expected by the end of 2024.

Q: HOW IMPORTANT IS STAKEHOLDER ENGAGEMENT IN THE MPSC'S DIRECTIVES REGARDING ENVIRONMENTAL JUSTICE, AND WHAT ROLE DOES IT PLAY?

A: Stakeholder engagement is crucial in the MPSC's directives regarding environmental justice. The Commission emphasized the need for DTE Electric to continue involving stakeholders in the development and evaluation of its distribution system plans. Engaging stakeholders, including affected communities, ensures that diverse perspectives are considered, and that the plans developed are inclusive and equitable. It is essential that DTE work in concert with affected communities to ensure that their needs are heard, understood, and addressed. Planning for affected communities without their input runs the risk that the plans will not meaningfully address the needs of impacted communities. This ongoing dialogue is essential for the iterative development of effective and just energy policies.

Q: HOW IS DTE CURRENTLY INCORPORATING EJ AND EQUITY CONSIDERATIONS INTO ITS DISTRIBUTION PLANNING PROCESS?

A: Witness Kryscynski explains that DTE has taken initial steps to incorporate equity into its distribution planning process. First, "the Company has included EJ scoring from the

MiEJScreen tool in the GPM calculation. Projects in more vulnerable areas will receive a higher score and have a better chance of being selected for investment."[24] In addition, the Company made efforts to address reliability performance in EJ communities that are served by the Company's worst performing circuits.[25] The Company states that it "intends to continue to include EJ considerations in investment decisions for all areas, as well as continue to address poor performing circuits in vulnerable communities."[26]

Q: WHAT SPECIFIC TOOLS AND METHODOLOGIES DID DTE ELECTRIC USE TO ADDRESS EJ IN THEIR PLANNING?

A: As directed by the Commission, DTE Electric leveraged the MiEJScreen tool to identify vulnerable communities. DTE adopted an 80th percentile threshold definition for vulnerable communities based on the MiEJScreen composite score,[27] consistent with the U.S. EPA's approach.[28]

Q: ARE THERE OTHER WAYS DTE CAN BETTER ACCOUNT FOR ENERGY JUSTICE COMMUNITIES IN ITS PLANNING AND SPENDING?

A: Yes. As discussed by CEO Witness Volkmann, as part of this rate case DTE analyzed the cost effectiveness of its PTMM and strategic undergrounding programs using the Interruption Cost Estimate ("ICE") calculator. While the ICE calculator is the best available resource to capture outage impacts, the disparate impacts of outages on disadvantaged communities is not reflected in the tool. The CEO request that the Company engage with stakeholders to discuss ways to quantify and incorporate the disparate impact

[24] AJK-100
[25] *Id.* at 100-101
[26] *Id.*
[27] DTE Ex. A-23 Sch. M-8 at 168.
[28] U.S. EPA, "How to Interpret EJScreen Data", https://www.epa.gov/ejscreen/how-interpret-ejscreen-data

of outages on disadvantaged communities into a Company or State specific implementation to the ICE calculator.

Q: WHAT WAS THE COMMISSION'S DIRECTIVE REGARDING THE ANALYSIS OF RELIABILITY PERFORMANCE IN EJ COMMUNITIES?

A: The Commission directed that future analyses of MiEJScreen data should be segmented in 5% gradations to better understand the distributional impacts. DTE Electric was instructed to provide a geographic representation of reliability data by census tract and to consider any updates from the final version of the MiEJScreen tool in its planning.[29] The Commission also ordered DTE to work with the Staff and other stakeholders to "develop a detailed regression analysis of customer demographics and reliability for vulnerable customers to be used in the company's distribution plan case."[30]

Q: WHAT IS REGRESSION ANALYSIS?

A: As explained by CEO witness Boratha Tan, regression is "a statistical model/method used to examine the relationship between a 'dependent variable' and one or more 'independent variables'... [and] is used to understand how these independent variables can predict (or influence) the outcome of the dependent variable".[31] Witness Tan further describes the importance of regression and the ways in which it can reveal relationships between grid performance and variables such as customer demographics and grid topology.

Q: WHAT DO YOU RECOMMEND DTE DO WITH THIS ANALYSIS?

A: I recommend the Company adopt regression analysis in both future rate cases and distribution grid plan cases as part of broader analysis that considers whether customers in

[29] Case No. U-21297, Final Order at 351 (Dec. 1, 2023).
[30] *Id.* at 352.
[31] Direct Testimony of CEO Witness Boratha Tan at 4.

EJ communities receive equitable service in reliability and other dimensions of utility of performance. Importantly, such analysis must then be used to inform the planning and investment decision-making process.

Q: WHAT RECOMMENDATIONS DO YOU HAVE FOR DTE ELECTRIC TO FULLY INTEGRATE ENVIRONMENTAL JUSTICE (EJ) INTO THEIR DISTRIBUTION SYSTEM PLANNING?

A: I am pleased that DTE is beginning to incorporate energy justice into its distribution planning process, but there is more work to be done. I recommend the following steps for DTE to fully integrate environmental justice into their distribution system planning process:

- **Develop Detailed Plans for Vulnerable Communities**: Create and implement detailed, actionable plans specifically targeting the most vulnerable communities identified by the MiEJScreen tool, focusing on improving reliability and reducing outage impacts.
- **Increase Transparency**: Provide comprehensive, visual, and data-informed analyses such as overlay maps, charts, and graphs to transparently show the impact of infrastructure investments on various communities. The Commission's current utility reliability reporting website[32] could be enhanced to include other dimensions of utility performance.
- **Enhance Stakeholder Engagement**: Strengthen and formalize stakeholder engagement processes to include continuous and meaningful input from

[32] MPSC Website: Distribution System Reliability Metrics, https://www.michigan.gov/mpsc/consumer/electricity/distribution-system-reliability-metrics

community representatives, advocacy groups, and other stakeholders throughout the planning and implementation phases.

- **Track GPM scores:** with DTE incorporating an EJ component in its GPM, the Company should track and provide progress on how EJ affects GPM scores over time.
- **Reliability Progress in EJ Communities:** DTE shall track its progress in improving reliability for customers in EJ communities; regression analysis demonstrated by Witness Tan is a great way to demonstrate progress.
- **Advance Mapping Tools:** as described earlier in my testimony, DTE shall work with interested stakeholders to implement a mapping tool that tracks metrics such as energy burden, disconnections, etc.
- **Grid Access**: Track and manage grid access in EJ communities.

Q: BEYOND CAPITAL PLANNING, HOW SHOULD DTE INCORPORATE EQUITY INTO ITS OPERATIONS?

A: DTE should also consider how equity is integrated into its operational practices. For example, the company should evaluate how it plans and executes storm responses, taking into account environmental justice and the disproportionate impact of outages on disadvantaged communities. This would ensure that operational decisions are made with a focus on minimizing the adverse effects on the most vulnerable populations.

IV. CONCLUSION AND RECOMMENDATIONS

Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A: In my testimony, I make the following major recommendations:

The Company should expand its use of cost-effectiveness in evaluating its spending proposals.

1. The Company should expand the focus of its equity work beyond reliability to include: grid access, energy burden and affordability, participation in energy assistance and EWR programs, and disconnect and arrearage management.
2. The Company should track its performance by census block not just census tract.
3. The Company should adopt regression analysis in both rate cases and its distribution grid plans.
4. The Company should fully integrate EJ into their distribution planning process through: developing detailed plans for vulnerable communities, increasing transparency into its processes, enhancing stakeholder engagement, tracking GPM scores and progress on how EJ impacts GPM scores, tracking reliability progress in EJ communities, adopting advanced mapping tools, and tracking grid and benchmarking grid access metrics.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes

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

REBUTTAL TESTIMONY OF

WILLIAM D. KENWORTHY

ON BEHALF OF

THE ECOLOGY CENTER, THE ENVIRONMENTAL LAW & POLICY CENTER, UNION OF CONCERNED SCIENTISTS, AND VOTE SOLAR

August 16, 2024

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I. INTRODUCTION AND SUMMARY

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is William D. Kenworthy (he/him). My business address is 1 South Dearborn Street, 20th Floor, Chicago, Illinois 60603.

Q. ARE YOU THE SAME WILLIAM KENWORTHY THAT PROVIDED DIRECT TESTIMONY IN THIS CASE?

A. Yes.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS IN THIS TESTIMONY.

A. In this testimony, I make recommendations supporting Witness Douglas Jester's suggestion to create separate rate classes for residential customers based on dwelling type and space heating type and encouraging electrification by offering rates for electric space heat customers that are more closely aligned to cost causation. Additionally, I concur with DAAO Witness Koeppel's assessment of the need for a comprehensive low-income affordability program within DTE Electric's rate structure, and I recommend that the Commission consider elements of ComEd's low-income discount proposal and Xcel Energy's low-income credit pilot to design a broad affordability program aimed at achieving a 3% electric energy burden for DTE customers. Lastly, I recommend that if the Commission permits DTE to proceed with migrating customers participating in the D1.6 rate to the D1.11 rate with the Low Income Assistance credit, the Commission should also require DTE to conduct further analysis of the usage patterns of low-consumption, low-income customers to help identify the most vulnerable customers and to expand its outreach

and programs to help low-income customers understand and mitigate the adverse impact of switching to a time-of-use rate.

II. COST ALLOCATION AND RATE DESIGN: CREATING A SPACE HEATING RATE FOR SINGLE FAMILY HOMES

Q: WHAT DOES WITNESS DOUGLAS JESTER RECOMMEND ABOUT CREATING A RESIDENTIAL ELECTRIC SPACE HEATING CLASS IN THE RATE DESIGN SECTION OF HIS TESTIMONY?

A: Witness Douglas Jester[1] recommends that the Commission direct the Company to "present in its next rate case a cost-of-service study and corresponding rates" for customers based on the type of dwelling unit (single-family or multi-family) and the type of space heating they use (electric or non-electric).[2] He suggests that residential customers be divided into three groups: Multi-Family, Single-Family with electric space heating, and Single-Family with fossil-fueled space heating. Witness Jester notes that there are significant differences in load profiles and infrastructure requirements between these groups, which could justify their separation into different rate classes to more accurately reflect the cost of service and reduce current inequities in electric utility bills.

Q: WITNESS JESTER BASES HIS RECOMMENDATION IN PART ON THE ANALYSIS OF WITNESS DAVID GARD. WHAT DID WITNESS GARD FIND WITH RESPECT TO DIFFERENCE IN USAGE PATTERNS BETWEEN SINGLE FAMILY VERSUS MULTI-FAMILY HOMES?

[1] Witness Jester appears on behalf of Citizens Utility Board of Michigan (CUB), Sierra Club (SC), Michigan Environmental Council (MEC), and Natural Resources Defense Council (NRDC).
[2] Direct Testimony of CUB, SC, MEC, NRDC Witness Douglas Jester at 24.

A: Witness Gard's[3] analysis emphasizes the distinct load profile differences between single-family and multi-family dwellings, particularly in terms of electric space heating, with single-family residences showing higher summer peaks and lower winter loads. This variation in Cost of Service (COS) parameters suggests the need for separate customer classifications and the exploration of time-differentiated rate structures for electric heating customers. Gard underscores the importance of assessing the distribution system's capacity to handle increased electric heating demand, especially with the rise of building electrification rates, to avoid significant upgrades. His focus on single-family detached buildings highlights their unique load profile challenges and the critical need to evaluate transformer capacity as winter peak loads approach summer levels.[4]

Q: DO YOU HAVE ANYTHING TO ADD TO WITNESS GARD'S AND WITNESS JESTER'S RECOMMENDATIONS?

A: I support Witness Gard's and Witness Jester's recommendations to create separate rate classes for residential customers based on dwelling type and space heating type. I would like to offer some additional context on a similar approach currently in practice in Illinois, where ComEd has implemented different rates for these customer groups that reflect the cost of service and grid utilization.

Q: ARE YOU AWARE OF OTHER UTILITIES THAT HAVE SEPARATE RATES FOR DIFFERENT TYPES OF RESIDENTIAL CUSTOMERS BASED ON SPACE HEATING AND DWELLING TYPE?

[3] Witness Gard appears on behalf of CUB, MEC and NRDC.
[4] Direct Testimony of CUB, MEC, NRDC Witness David Gard at 3-5.

A: Yes. ComEd in Illinois has established separate rates for residential customers based on whether they live in single-family or multi-family dwellings and whether they use electric or non-electric space heating. These rate distinctions reflect the significant differences in daily and seasonal grid utilization among these customer groups. I am also aware that there are other similar proposed and approved rates for electric space heat.[5]

Q: HOW DO THE RATES VARY AMONG THESE DIFFERENT CUSTOMER CLASSES AT COMED?

A: The rates vary substantially among these classes due to the differences in load profiles and how they impact the grid. Single-family homes with electric space heating, for example, tend to have higher peak demands during winter, whereas single-family homes without electric space heating are generally summer-peaking. Similarly, multi-family dwellings also show distinct patterns depending on their heating type. The rates that result from the cost-of-service studies as implemented in Illinois ensure that each group pays rates that are more closely aligned with the costs they impose on the grid. ComEd's current delivery service rate structure consists of four delivery classes:

- Residential Single Family Without Electric Space Heat (SFNH)
- Residential Multi Family Without Electric Space Heat (MFNH)
- Residential Single Family With Electric Space Heat (SFH)
- Residential Multi Family With Electric Space Heat (SFNH)

The delivery service charges for each class consist of four cost components:

- Customer Charge (CC)

[5] Kresowik, Mark, New Electricity Rates Are Needed to Support Equitable Heat Pump Adoption, American Council for an Energy-Efficient Economy, July 11, 2024. Accessed on August 14, 2024 at https://www.aceee.org/blog-post/2024/07/new-electricity-rates-are-needed-support-equitable-heat-pump-adoption

- Standard Metering Service Charge (SMSC)
- Distribution Facilities Charge (DFC)
- Illinois Electricity Distribution Tax Charge (IEDT)

Two of these components are the same for each of the four customer classes (the Standard Metering Service Charge and the Illinois Electric Distribution Tax), so they are excluded from the table below. The table below illustrates the variation for the combination of the Customer Charge (which is a fixed monthly rate) and the Distribution Facilities Charge (a volumetric rate that includes most distribution facilities cost categories) for customers in these four classes. Also excluded from these charges is an adjustment factor for uncollectible costs, which does not vary. These rates are taken from the current ComEd Ratebook and are in effect for the current billing period.[6]

Customer Charges ($/month)	**No Space Heat**	**Space Heat**
Single Family	$ 12.45	$ 14.28
Multi Family	$ 9.33	$ 10.14
Distribution Facilities Charge ($/kWh)	**No Space Heat**	**Space Heat**
Single Family	$ 0.0488	$ 0.0234
Multi Family	$ 0.0373	$ 0.0222
Delivery Service Charges for 1,500 kWh	**No Space Heat**	**Space Heat**
Single Family	$ 85.70	$ 49.38
Multi Family	$ 65.33	$ 43.50

[6] Commonwealth Edison Company, Delivery Service Charges, Supplement to Rate MPP, Ill. C.C. No. 10, 3rd Revised Informational Sheet no. 64.

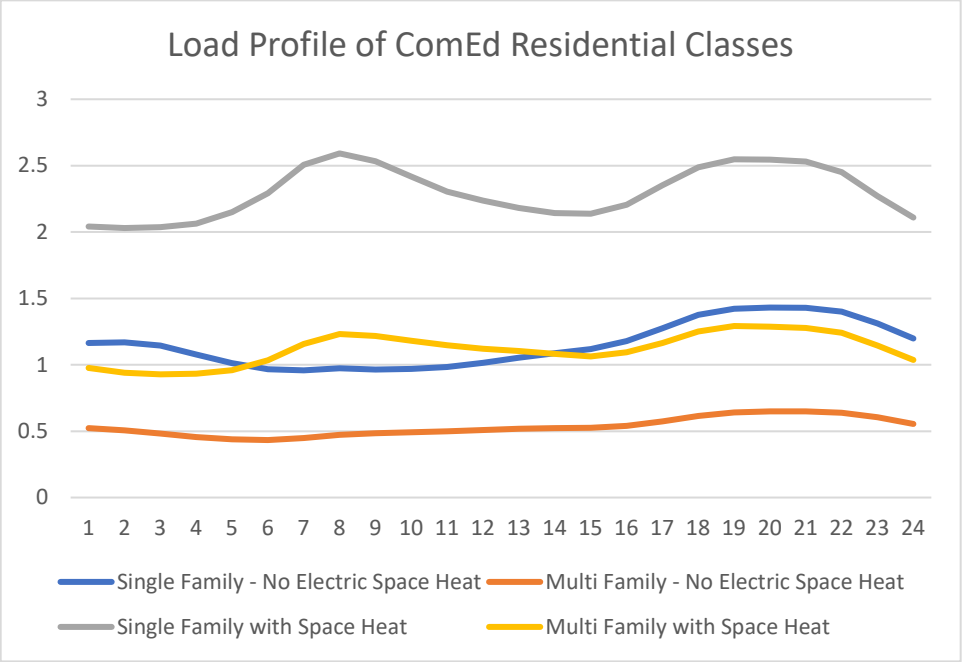
Q: WHAT DOES THIS CHART DEMONSTRATE ABOUT COMED'S DIFFERENT RATES?

A: Electric heating customers have a higher fixed customer charge which corresponds to higher demand peaks, but electric heating customers also pay significantly lower in volumetric distribution/delivery charges because of higher load factors and higher usage during times of low grid utilization.

Q: WHAT EVIDENCE SUPPORTS THESE RATE DISTINCTIONS?

A: I have prepared a figure that illustrates the load profiles of the different customer classes who participate in ComEd's residential real-time pricing program. The figure clearly shows the variations in daily and seasonal grid utilization among these classes, further illustrating the differences between different groups:

Figure 1: Load Shapes of ComEd Real Time Pricing Customers by Delivery Service Class



Q: HOW WOULD ADOPTING WITNESS JESTER'S RECOMMENDATION ALIGN WITH MICHIGAN'S DECARBONIZATION POLICY?

A: Adopting Witness Jester's recommendation to create separate rate classes for residential customers based on their dwelling type and heating source would strongly align with Michigan's policy of pursuing decarbonization. By recognizing the different cost implications and grid impacts of electric versus non-electric heating, this approach would create rate structures that encourage the electrification of building heat, a key strategy in reducing carbon emissions.

Q: HOW WOULD THIS RATE STRUCTURE ENCOURAGE ELECTRIFICATION?

A: The proposed rate structure would offer rates for electric space heat customers who are more closely aligned to cost causation and potentially lower for customers that choose electric space heating, especially during off-peak times when the grid is underutilized. This would make electrification more financially attractive, thereby encouraging more customers to switch from fossil-fueled heating to electric alternatives, which are essential for achieving the state's decarbonization goals.

Q: WHAT IMPACT WOULD THIS HAVE ON LOW-INCOME CUSTOMERS?

A: Adopting this recommendation would make electrification more accessible to all customers, including low-income households participating in whole home energy upgrades. By offering rate structures that reflect the true cost of electric heating, low-income customers could benefit from lower energy costs, especially when combined with energy efficiency upgrades. This could be particularly impactful for those in multi-family dwellings with electric heating, helping to reduce energy burden and support broader adoption of clean energy solutions among low-income populations.

Q: WHY IS THIS IMPORTANT FOR MICHIGAN'S ENERGY POLICY?

A: Aligning rate structures with the state's decarbonization policy not only supports the transition to cleaner energy sources but also ensures that all customers, regardless of income, can participate in and benefit from this transition. By making electrification of building heat more affordable and accessible, Michigan can accelerate its progress towards its decarbonization goals while promoting energy equity.

Q: WOULD YOU CHANGE ANYTHING ABOUT WITNESS JESTER'S RECOMMENDATION?

A: I would suggest that the Commission also consider including a separate rate class for multi-family units with in-unit electric space heating, as this group may have different load profiles and cost implications than single-family units with electric space heating. This would further enhance the accuracy and equity of the rate structure and encourage more low-income customers in multi-family dwellings to switch to electric heating.

Q: WHAT WERE WITNESS GARD'S RECOMMENDATIONS REGARDING A MORE ROBUST TIME DIFFERENTIATED RATE FOR ELECTRIC SPACE HEAT CUSTOMERS?

A: Witness Gard provided analysis that demonstrated the impacts of different decarbonization approaches to grid utilization. In addition to creating a separate rate class for electric space heat customers, Gard also recommended consideration of a "robustly time-differentiated rate structure" to further strengthen the price signal encouraging beneficial electrification and improving grid utilization.[7]

[7] Gard Direct at 10.

Q: DO YOU SUPPORT DEVELOPING MORE ROBUSTLY TIME DIFFERENTIATED RATES?

A: Yes, for the reasons cited by Witness Gard. In addition, I would note that Solar Energy Industry Association Witness Kevin Lucas provided testimony on behalf of the CEO groups in DTE's 2022 rate case, U-20836, in which he "recommended[ed] the Commission direct the Company to redesign its D1.11 rate to substantially increase the TOU differential to better reflect the underlying cost of providing energy during peak hours."[8]

Q: WHAT RECOMMENDATION WOULD YOU MAKE TO THE MICHIGAN PUBLIC SERVICE COMMISSION (MPSC) REGARDING THIS ISSUE?

A: I recommend that the Commission adopt Witness Jester's recommendation to require DTE Electric to conduct a cost-of-service study and propose corresponding rates for the three residential sub-classes that he recommends: Multi-Family, Single-Family with electric space heating, and Single-Family with fossil-fueled space heating. In addition, I recommend that the Commission also consider including a separate rate class for multi-family units with in-unit electric space heating. Given the significant differences in grid utilization among these groups, as demonstrated by ComEd's experience in Illinois, this approach would lead to more equitable and cost-reflective rates for Michigan's residential customers.

[8] Case No. U-20836, Direct Testimony of Kevin Lucas on behalf of the Ecology Center, the Environmental Law & Policy Center, Vote Solar and the Union of Concerned Scientists at 25.

III. ENERGY AFFORDABILITY PROPOSALS

Q: WHAT DID DETROIT AREA ADVOCACY ORGANIZATIONS (DAAO) WITNESS JACKSON KOEPPEL PROPOSE REGARDING A LOW-INCOME AFFORDABILITY PROGRAM?

A: Witness Jackson Koeppel proposed the creation of a comprehensive low-income affordability program within DTE Electric's rate structure.[9] His proposal aimed to address the existing affordability gap for electricity bills in DTE Electric's service territory.

Q: HOW LARGE IS THE AFFORDABILITY GAP THAT DAAO WITNESSES IDENTIFIED, AND WHAT DID THEY PROPOSE TO CLOSE IT?

A: In his testimony, DAAO Witness Yunus Kinkhabwala identified an electricity affordability gap of $380 million in DTE Electric's service territory.[10] After accounting for existing affordability programs, Witness Koeppel estimates that an additional $304 million is needed to close the electric affordability gap.[11] He proposed including this amount as an operating expense in DTE Electric's revenue requirement, which would be distributed equally across all customer bills to help cover the affordability gap.

Q: HOW WOULD THE PROPOSED AFFORDABILITY PROGRAM WORK?

A: The program would involve DTE Electric verifying a customer's income and their electricity costs over the last twelve months. If these costs exceeded 6% of the customer's annual income, DTE Electric would immediately credit the amount accrued in excess of that threshold to the customer's account. Additionally, the company would calculate the

[9] Witness Koeppel provided testimony on behalf of the Detroit Area Advocacy Organizations, consisting of Soulardarity and We Want Green Too.
[10] Direct Testimony of DAAO Witness Yunus Kinkhabwala at 36.
[11] Direct Testimony of DAAO Witness Jackson Koeppel at 24.

percentage of the customer's bills that exceeded the affordability threshold and apply a monthly affordability credit moving forward.

Q: WHAT RATIONALE DID WITNESS KOEPPEL PROVIDE FOR ADDRESSING AFFORDABILITY THROUGH THE RATE STRUCTURE RATHER THAN THROUGH LEGISLATIVE ACTION?

A: Witness Koeppel argued that addressing the affordability crisis through the rate structure would provide a complete solution within the context of regulatory intervention, removing the need for legislative action. He also noted that this approach would help eliminate costly and punitive collection practices that disproportionately affect low-income customers.[12]

Q: DO YOU CONCUR WITH THE AFFORDABILITY GAP IDENTIFIED BY JACKSON KOEPPEL AND DAAO WITNESS YUNUS KINKHABWALA?

A: Yes. I concur with the affordability gap of $380 million that was identified by Jackson Koeppel and DAAO Witness Yunus Kinkhabwala.[13]

Q: DO YOU AGREE WITH THE NEED FOR A LOW-INCOME BILL ASSISTANCE PROGRAM?

A: Yes. I agree with the need for a low-income bill assistance program that would be spread across the entire rate base as an operating expense. This program should be designed to reduce the electric energy burden to 3% of income for customers who use non-electric space heat sources, such as gas or propane, for building heat and to 6% of income for customers who use electric space heating.

[12] Koeppel Direct at 26.
[13] Kinkhabwala Direct at 36.

Q: CAN YOU PROVIDE EXAMPLES OF A POTENTIAL LOW-INCOME ASSISTANCE PROGRAM THAT COULD BE CONSIDERED?

A: Yes. I would like to provide an example of a potential program that could be considered: the ComEd Low Income Discount Rate, which is currently under consideration in Illinois in ICC Docket No. 24-0163. Additionally, I will discuss Xcel Energy's proposed pilot program in Minnesota to provide automatic bill credits for customers in certain low-income, high-energy-burdened areas.

Q: WHAT IS COMED'S LOW INCOME DISCOUNT RATE (LID) PROPOSAL CURRENTLY UNDER CONSIDERATION IN ILLINOIS?

A: ComEd's Low Income Discount Rate (LID) proposal, as detailed in the Illinois Commerce Commission (ICC) Docket No. 24-0163, aims to provide financial relief to low-income customers by offering a percentage-based discount on their electricity bills. The LID program is designed with five income tiers, segmented by delivery class (such as single-family or multi-family, and space heating or non-space heating). Residential customers with incomes between 0% and 300% of the Federal Poverty Level (FPL) will qualify for the discount, which will be applied to all enrolled customer bills. The program's goal is to ensure that enrolled customers maintain an energy burden—defined as the total home energy costs as a percentage of household income—within the threshold of 3% for electric-only households or 6% for households using electric space heating.

Q: HOW DOES COMED PLAN TO IMPLEMENT AND FUND THIS LID PROGRAM?

A: The costs of ComEd's LID program will be recovered from all customers, including those enrolled in the program. This approach ensures that the financial responsibility for the

discount is shared across the entire customer base, allowing ComEd to provide meaningful assistance to low-income customers while minimizing the bill impacts on non-enrolled residential and commercial customers. The program also includes provisions for automatic enrollment for customers already identified as low-income, with the flexibility for these customers to apply through existing channels.

Q: DO YOU SUPPORT COMED'S LOW INCOME DISCOUNT RATE PROPOSAL?

A: Yes. I supported the proposal with qualification and recommendations for improvement detailed in my testimony in that case. While the proposal effectively addresses the needs of low-income customers and aligns with affordability and equity goals, certain aspects of the program might require adjustments to better serve the target population. Despite these qualifications, the proposal provides a valuable framework that can be considered and further refined in our discussions.

Q: ARE THERE ANY OTHER EXAMPLES OF PROGRAMS THAT PROVIDE ASSISTANCE TO LOW-INCOME CUSTOMERS THAT SHOULD BE CONSIDERED?

A: Yes. As mentioned in my Direct Testimony, Xcel Energy in Minnesota recently unveiled a two-year pilot that would provide automatic bill credits for customers in certain low-income, high-energy-burdened areas. Specifically, if approved, the Automatic Bill Credit Pilot Petition will bring the median energy burden in all census block groups in Xcel Energy's service territory down to 4%; the bill credit will go to approximately 23,000 households in 77 census block groups. The automatic credit occurs without active enrollment from the household, eliminating the need for customers with high energy

burdens to apply for energy assistance. The pilot petition is currently pending before the Minnesota Public Utilities Commission, and a decision is expected by the end of 2024.

Q: DO YOU SUPPORT WITNESS KOEPPEL'S RECOMMENDATION TO FORM A STAKEHOLDER GROUP TO IMPLEMENT HIS AFFORDABILITY PROPOSAL?

A: Yes. I support Witness Koeppel's suggestion to form a stakeholder group to consider and potentially implement an affordability proposal. I understand that the Commission may not have the authority to order implementation of a low-income discount rate in this proceeding. However, I believe that convening a diverse group of stakeholders, including community representatives, to collaboratively explore and refine these proposals would be a valuable step towards developing a low-income affordability program that effectively addresses the needs of vulnerable populations and ensures equitable access to energy.

IV. <u>CLOSING RATE D1.6</u>

Q: WHAT IS DTE ELECTRIC PROPOSING WITH REGARD TO THE D1.6 RATE AND D1.11 RATE?

A: DTE Electric is proposing to close the D1.6 rate, which is a declining block rate, and transition customers currently on this rate to the D1.11 rate, which is a Time-of-Use (TOU) rate.

Q: WHAT CONCERNS DID DAAO WITNESS KOEPPEL AND THE DAAO RAISE REGARDING THIS PROPOSAL?

A: Witness Koeppel expressed concerns that transitioning customers from the D1.6 rate to the D1.11 TOU rate could negatively impact low-income and vulnerable customers. He argued that TOU rates might not align well with the energy consumption patterns of these

customers, potentially leading to higher bills or difficulty in managing energy usage during peak periods.

Q: DID WITNESS KOEPPEL AND THE DAAO OPPOSE THE IMPLEMENTATION OF TOU RATES?

A: While he did not outright oppose TOU rates, Witness Koeppel emphasized the need for a comprehensive analysis of the potential impacts on low-income and vulnerable customers before making the transition. He stressed that any rate changes should not exacerbate the financial burdens on these populations.

Q: WHAT DID WITNESS KOEPPEL RECOMMEND REGARDING THE TRANSITION FROM THE D1.6 RATE TO THE D1.11 RATE?

A: He recommended that DTE Electric should conduct a thorough impact study to assess the effects on low-income and vulnerable customers. He also advocated for providing adequate protections or alternative rate options for these customers and suggested delaying or modifying the transition until these concerns are adequately addressed.

Q: WHAT SPECIFIC SHORTCOMINGS DID WITNESS KOEPPEL IDENTIFY IN DTE'S ANALYSIS?

A: He pointed out that DTE's analysis lacked a comprehensive evaluation of the financial and practical implications for customers currently on the D1.6 rate. The analysis did not consider how these customers, many of whom are low-income, might struggle with the variability of TOU rates, potentially leading to higher overall energy costs or increased difficulty in managing their energy use effectively.

Q: HOW DID WITNESS KOEPPEL SUGGEST THAT DTE'S ANALYSIS COULD BE IMPROVED?

A: He suggested that DTE should conduct a more thorough impact study that specifically focuses on the unique challenges faced by low-income and vulnerable customers. This study should include an assessment of energy consumption patterns, the ability of these customers to shift usage to off-peak times, and the potential financial impacts of the rate change. Additionally, he recommended that DTE explore alternative rate structures or protective measures to mitigate any negative effects identified in the analysis.

Q: DID DTE CONDUCT THE STUDY RECOMMENDED BY WITNESS KOEPPEL?

A: No.

Q: DID YOU CONDUCT ANY ANALYSIS ON HOW LOW-INCOME CUSTOMERS WOULD HAVE BEEN IMPACTED IF THEY WERE ON THE D1.11 RATE IN PREVIOUS YEARS INSTEAD OF THE CURRENT D1.6 RATE?

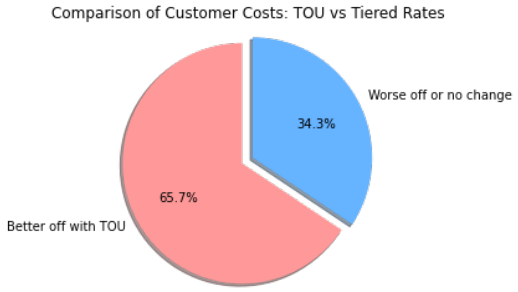
A: Yes. I conducted a preliminary analysis to determine the savings or losses that low-income customers would have experienced had they been on the D1.11 Time-of-Use (TOU) rate rather than the D1.6 declining block rate in previous years.

Q: WHAT WAS THE METHODOLOGY OF YOUR ANALYSIS?

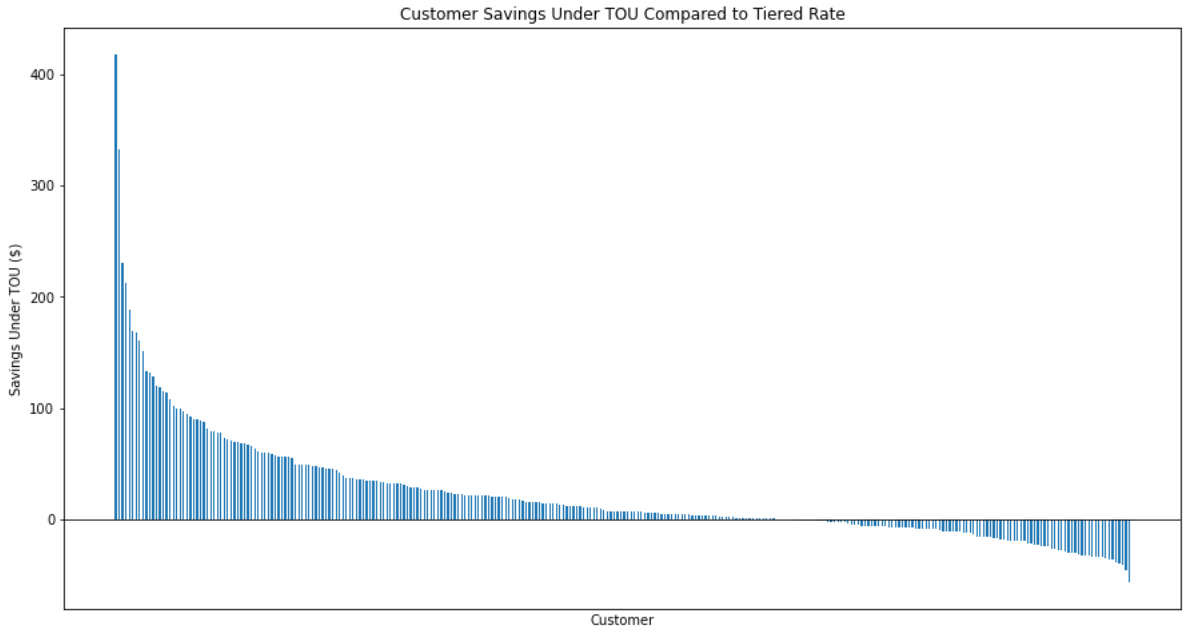
A: The methodology involved comparing the charges that customers would have incurred under the current D1.11 TOU rates with the charges they would have incurred under the current D1.6 rates for the years 2021, 2022, and 2023. The analysis focused solely on volumetric power supply costs and did not include any riders, fixed charges, taxes, or fees. I used data provided by DTE in response to CEO Discovery Request 1, which included hourly interval data for 300 customers participating in income-qualified programs from 2021 to 2023.

Q: WHAT WERE THE KEY FINDINGS OF YOUR ANALYSIS?

A: The results of my analysis showed that nearly two-thirds of customers (65.7%) would have been better off under the TOU rate.



Additionally, the customer savings for the entire group were generally larger than any losses. This suggests that low-income customers are generally better off under a TOU rate.



Q: WHAT CONCLUSIONS DID YOU DRAW FROM YOUR ANALYSIS?

A: I found that low-income customers in the sample provided by DTE generally benefit from being on a Time-of-Use rate.

Q: WHAT COULD THE COMPANY DO TO MITIGATE THE POTENTIAL NEGATIVE IMPACTS OF ADVERSELY IMPACTED LOW-INCOME CUSTOMERS OF TRANSITIONING TO TIME-OF-USE RATES?

A: With some simple behavioral changes, most customers will have the opportunity for increased savings under a time-of-use rate. For those customers who would experience losses (in the form of higher bills compared to the declining block rate), I recommend that the Company expand its outreach to low-income customers. This outreach should focus on educating them about opportunities to save money and providing them with the tools—such as low-income energy efficiency programs, weatherization, and technology like smart thermostats—to further reduce their bills without compromising comfort or safety. To the extent that such adjustments are not possible, the Company should develop programs to directly address the energy burden of those customers, such as the low-income discount discussed above. Finally, I also recommend that the Commission direct DTE to develop a plan to use smart meter data to identify and address customers who engage in energy-limiting-behavior that is averse to health and safety.

Q: PLEASE EXPLAIN WHAT YOU MEAN BY ADVERSE ENERGY-LIMITING-BEHAVIOR.

A: In testimony submitted in ComEd's integrated grid plan case in Illinois in 2023, Dr. Destenie Nock addressed her studies on energy-limiting-behavior by low-income customers and adverse impacts on low income customers.[14]

Q: WHAT DOES DR. NOCK MEAN BY "ENERGY-LIMITING-BEHAVIOR"?

[14] Nock, Destenie. Direct Testimony on Behalf of Environmental Law & Policy Center, Natural Resources Defense Council, Union of Concerned Scientists, Vote Solar, and Environmental Defense Fund. ICC Docket No. 22-0487, May 11, 2023.

A: Dr. Nock defines energy-limiting-behavior as the practice where households reduce their energy usage significantly below the level required to maintain a comfortable and safe indoor environment. This is often a consequence of financial constraints, where households, particularly low-income ones, cannot afford to pay their energy bills and, therefore, use less energy than needed to avoid excessive costs.

Q: HOW DOES ENERGY-LIMITING BEHAVIOR AFFECT LOW-INCOME CUSTOMERS?

A: Energy-limiting behavior can severely impact low-income customers by forcing them to live in unsafe conditions. For example, during heatwaves or cold winters, low-income households may delay turning on air conditioning or heating to save on energy costs, which can lead to heat-related illnesses, respiratory problems from cold and damp environments, or even death in extreme cases. This behavior highlights the intersection of energy poverty and health risks, as families are forced to choose between financial stability and their well-being.

Q: WHY IS THIS DISCUSSION OF ENERGY-LIMITING BEHAVIOR RELEVANT IN THIS CONTEXT?

A: It is possible that energy-limiting-behavior could be exacerbated by a transition to a time-of-use rate. Addressing this phenomenon should be part of the plan to identify customers who may not be able to respond to time-of-use signals or who are experiencing adverse energy-limiting-behavior

Q: WHAT OTHER ISSUES SHOULD THE COMMISSION CONSIDER IN THE TRANSITION FROM THE CURRENT DECLINING BLOCK STRUCTURE TO TIME-OF-USE RATES FOR LOW-INCOME CUSTOMERS?

A: The current D1.6 rate is based on a declining block rate, which is itself regressive. Under this pricing structure, basic consumption is charged at a higher rate, while larger consumers pay less for each additional unit of electricity. This places a heavier burden on low- and moderate-income households, which typically consume less electricity but pay a higher rate for their basic needs. As a result, declining block rates exacerbate income inequality by making electricity more affordable for wealthier consumers, while lower-income households bear a relatively higher cost as a percentage of their income.

Q: WHAT DO YOU RECOMMEND?

A: I recommend that, if the Commission permits DTE to proceed with migrating customers participating in the D1.6 rate to the D1.11 rate with the Low Income Assistance credit, the Commission should also require DTE to conduct further analysis of the usage patterns of low-consumption, low-income customers to help identify the most vulnerable customers and to expand its outreach and programs to help low-income customers understand and mitigate the adverse impact of switching to a time-of-use rate.

V. CONCLUSION AND RECOMMENDATIONS

Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A: In my rebuttal testimony I make the following major recommendations:

1. Cost Allocation and Rate Design:
    - Support for creating separate rate classes for residential customers based on dwelling type and space heating type.
    - Encourage electrification by offering rates for electric space heat customers who are more closely aligned to cost causation.
2. Energy Affordability Proposals:

- Concur with Witness Koeppel's assessment of the need for a comprehensive low-income affordability program within DTE Electric's rate structure.
- Recommend that the Commission consider the elements of ComEd's low-income discount proposal and Xcel Energy's low-income credit pilot in designing a broad affordability program designed to achieve 3% electric energy burden for DTE customers.

3. Closing Rate D1.6:

- If the Commission permits DTE to proceed with migrating customers participating in the D1.6 rate to the D1.11 rate with the Low Income Assistance credit, that the Commission should also require DTE to conduct further analysis of the usage patterns of low-consumption, low-income customers to help identify the most vulnerable customers and to expand its outreach and programs to help low-income customers understand and mitigate the adverse impact of switching to a time-of-use rate.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

MR. ABRAMS: At this time, on behalf of the Clean Energy Organizations and by stipulation of the parties, I move to bind in the Direct Testimony of Curt Volkmann, consisting of a cover page, a table of contents, and 29 pages of questions and answers, and I'd move for the admission of Exhibits CEO-4 and CEO-5.

JUDGE WALLACE: And the witness's name again was?

MR. ABRAMS: Curt Volkmann, V-o-l-k-m-a-n-n.

JUDGE WALLACE: Is there any objection to binding in the Direct Testimony of Mr. Volkmann?

Hearing none, the testimony is bound in.

Is there any objection to the admission of Exhibits CEO-4 through CEO-5?

Hearing none, those exhibits are admitted.

(Testimony bound in.)

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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

DIRECT TESTIMONY OF

CURT VOLKMANN

ON BEHALF OF

THE ECOLOGY CENTER, THE ENVIRONMENTAL LAW & POLICY CENTER, UNION OF CONCERNED SCIENTISTS, AND VOTE SOLAR

July 26, 2024

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I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q: PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A: My name is Curt Volkmann. My business address is 1400 Waterview Way, Lake Geneva, Wisconsin, 53147. I am President and founder of New Energy Advisors, LLC.

Q: PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A: I have a BS in Electrical Engineering from the University of Illinois with a concentration in Electrical Power Systems. I also have an MBA from the University of California at Berkeley with a concentration in Finance. I have 40 years of experience in the utilities industry, primarily in electric transmission and distribution. My work experience includes nine years at Pacific Gas & Electric in various transmission and distribution engineering roles, and eighteen years at Accenture with several positions including Executive Director in the North American Utilities practice. Since 2015, I have worked independently and supported clients in various distribution planning and grid modernization regulatory proceedings across the United States. Ex. CEO-4 provides a statement of my qualifications and experience.

Q: HAVE YOU PREVIOUSLY TESTIFIED OR COMMENTED BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION ("COMMISSION" OR "MPSC")?

A: Yes. I have testified before the MPSC in Case No. U-17752 and contributed to comments in Case No. U-20147. I have also testified and commented before regulatory commissions in fourteen other states. Ex. CEO-5 provides a summary of my prior testimony and contributions to comments.

Q: ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A: I am submitting testimony on behalf of the Ecology Center, Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar (collectively, the Clean Energy Organizations ("CEO")).

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A: I provide an assessment of this rate case application of the DTE Electric Company ("DTEE" or "the Company") as it relates to distribution planning and the transformation of DTEE's distribution system.

Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A: I recommend that the Commission require DTEE to:

1) Provide enhanced reporting of circuit-level reliability program results (for Tree Trimming, 4.8kV Hardening, Pole Top Maintenance and Modernization, 4.8kV Conversions, and Distribution Automation) compared to the Company's reliability improvement projections.
2) Work with Staff and interested stakeholders to design a Virtual Power Plant pilot/demonstration project for resilience and peak load reduction use-cases using a third-party aggregator, and to include the pilot/demonstration in its 2025 Distribution Grid Plan ("DGP").
3) Work with Staff and interested stakeholders to define its approach for scaling up piloted technologies and incorporating Non-wires Alternative ("NWA") solutions into its distribution planning process. DTEE should explain the approach in its next DGP.

I also request that DTEE, in rebuttal testimony, confirm that it will:

1) Provide additional information about Environmental Justice ("EJ") Community impacts in its next DGP, including how customers are benefitting from investments and confirming that these benefits are the ones the communities prioritize.

2) Conduct one or more Technical Conferences to further explain its Global Prioritization Model to Staff and stakeholders and explain how it differs from a benefit-cost analysis ("BCA").
3) Conduct one or more Technical Conferences to help Staff and stakeholders understand the Distribution Automation Prioritization Model's assumptions and calculations.
4) Expand its Reliability Model to include the impacts from Underground Residential Distribution ("URD") Replacement, Cable Replacement, Breaker Replacement, and Substation Risk projects and include the enhanced model in its next DGP.
5) Collect and incorporate actual outage data to refine the assumptions in its Reliability Model.
6) Refresh its assumptions in the Distribution Automation Prioritization Model with the actual customer interruption and outage duration impacts from automation as the data become available.
7) Expand the Company's application of its BCA methodology to its 4.8kV Conversion, Distribution Automation, Frequent Outage, Subtransmission Redesign & Rebuild, Breaker Replacement, URD Replacement, Cable Replacement, and Tree Trimming Surge programs.
8) Make necessary modifications to its outage management systems to begin incorporating actual DTEE failure data in its BCA methodology.
9) Consider partnering with Lawrence Berkeley National Lab to quantify the resilience impacts of DTEE's planned investments using the Power Outage Economics Tool, for inclusion in future BCAs.
10) Modify the BCA methodology to reflect the full revenue requirements of investments.

II. OVERVIEW

Q: PLEASE PROVIDE A BRIEF ASSESSMENT OF DTEE'S SITUATION.

A: DTEE faces a monumental task to transform its aging distribution system and to cost-effectively improve reliability. In the annual Institute of Electrical and Electronics Engineers ("IEEE") reliability benchmarking report, the Company has performed in the fourth quartile (worst) in all-weather SAIDI for six of the last seven years.[1] DTEE plans to spend $9 billion from 2024-2028[2] to rebuild, modernize, and automate 46,000 miles of electric circuits to achieve reliability that is better than industry average by 2029.[3] DTEE is projecting that its planned 2024-2028 investments will:

- Improve all-weather SAIDI from a baseline of 563 to 173 minutes per customer in 2029 (a 69% improvement).
- Improve all-weather SAIFI from a baseline of 1.37 to 0.91 interruptions per customer in 2029 (a 34% improvement).[4]

The Company estimates that this reliability improvement by 2029 will provide $15 billion of economic benefits for its customers.[5] However, investments of this magnitude will have major impacts on customer bills and affordability.

As the CEO recommended in prior proceedings, transparent grid planning to identify innovative solutions, including non-conventional but cost-effective customer-owned and third-party solutions, is critically important. As DTEE faces the daunting challenge of transforming its distribution system, transparent planning with a robust cost-

[1] Kryscynski Direct at AJK-19, Figure 2.
[2] Crozier Direct at AFC6:1–2.
[3] Crozier Direct at AFC5:7–9.
[4] WP AJK U-21534 Reliability Model, tab 'Reliability Projections', rows 12 and 17.
[5] Crozier Direct at AFC-8:14.

effectiveness framework gives the Commission, Staff and stakeholders confidence that the Company is considering and deploying the most cost-effective solutions (i.e., solutions with customer benefits exceeding customer costs).

III. DTEE's RESPONSE TO PRIOR CEO RECOMMENDATIONS

Q: HAVE THE CEO PREVIOUSLY MADE RECOMMENDATIONS ON DTEE'S DISTRIBUTION GRID PLAN?

A: Yes. In Case No. U-20147, the CEO provided comments on DTEE's 2023 Electric Distribution Grid Plan ("DGP").[6] Among other topics, we requested that DTEE:

- Provide more transparency into DTEE's planning and investment prioritization processes, including its Global Prioritization Model ("GPM").
- Develop a BCA methodology for demonstrating that the customer benefits of DTEE's planned investments exceed the customer costs.
- Provide a more robust evaluation of Conservation Voltage Reduction and Volt Var Optimization ("CVR/VVO") and consider a more aggressive deployment plan.
- Explain its NWA evaluation framework, including the cost thresholds and evaluation criteria the Company intends to employ to determine whether an NWA may be an appropriate solution for a projected grid need, as well as the solution-sourcing process DTEE will use to solicit NWA proposals from the market.
- Consider non-conventional solutions for transforming its distribution system that balance important factors such as reliability, affordability, equity, and energy justice. These may include more energy waste reduction including CVR/VVO,

[6] MPSC Case No. U-20147, Comments on DTE Electric's 2023 Electric Distribution Grid Plan Submitted by the Ecology Center, the Environmental Law & Policy Center, Union of Concerned Scientists, & Vote Solar, March 15, 2024.

utility-scale solar plus storage, microgrids, virtual power plants, and geo-targeted energy waste reduction and demand response.

Q: IN DTEE'S PREVIOUS RATE CASE, DID THE COMMISSION ADDRESS THE NEED FOR INCREASED TRANSPARENCY IN DISTRIBUTION PLANNING?

A: Yes. Its U-21297 order states:

> The Commission notes that DTE Electric presented the GPM and the DGP as the sole sources of support offered by the company for many capital expenditure programs in the distribution category. The Commission requires greater transparency into the basis for the GPM and the internal review process, as well as some explanation for the instances where the company deviated from the GPM's conclusions and sought funding for projects that were assigned a low priority. Without this additional information on how the rankings were arrived at, assessments of reasonableness and prudence are hampered and at times impossible. The Commission also expects DTE Electric to provide adequate supporting information, either in its initial rate case filing or in response to discovery, when intervenors seek basic information on the company's assertions about priority and need.[7]

Q: HOW HAS DTEE RESPONDED?

A: As I describe in my testimony, DTEE has responded well to the Commission's Order and the CEO's prior recommendations by providing increased transparency, developing a BCA methodology, increasing CVR/VVO deployment, and piloting non-conventional solutions. These are all good first steps towards meeting the Commission's expectations for greater transparency in distribution planning to support the Company's proposed investments in rate cases.

IV. DTEE HAS INCREASED TRANSPARENCY INTO ITS PLANNING PROCESS

Q: HOW HAS DTEE RESPONDED TO THE COMMISSION'S AND CEO'S REQUEST FOR INCREASED TRANSPARENCY INTO ITS PLANNING PROCESSES?

[7] MPSC Case No. U-21297 December 1, 2023 Order, p. 71.

A: In this proceeding, DTEE has fully disclosed to Staff and CEO its Global Prioritization Model, Reliability Model, and Distribution Automation ("DA") Prioritization Model. In addition to providing the models, DTEE hosted calls with the CEO to explain the models and answer our questions.[8]

A. DTEE's Global Prioritization Model (GPM)

Q: WHAT IS THE GPM?

A: The GPM is a tool DTEE uses to prioritize investments by ranking projects and programs based on the benefits the project or program delivers for a given level of investment. The Company evaluates projects across ten impact dimensions,[9] which represent project benefits, and develops a total project score based on the weighting of each impact dimension and the project cost. The GPM results serve as the initial basis for the Company's investment prioritization and highlight those projects that have the highest relative benefit and/or are most urgent.[10]

Q: HAS DTEE MODIFIED THE GPM IN RESPONSE TO THE COMMISSION'S DIRECTIVES REGARDING EQUITY?

A: Yes. The Commission ordered the Company to "fully incorporate equity considerations into its decision-making processes."[11] In response, DTEE added an "Investment in EJ Communities" impact dimension to the GPM, which reflects the percentage of customers benefiting from a project who are from EJ communities.[12]

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[8] DTEE and the CEO met virtually on April 5, April 16, May 14, May 15, June 28, July 8, and July 23, 2024.
[9] The impact dimensions are Reduce Electrical Hazards, Overload Relief, SAIDI, SAIFI, Regulatory Compliance, Major Event Risk, Capacity Relief, Investment in EJ Communities, O&M Avoidance, and Capital Avoidance.
[10] Kryscynski Direct at AJK-54:17-24.
[11] MPSC Case No. U-20836, November 18, 2022 Order, p. 459.
[12] Kryscynski Direct at AJK-60:15–16.

Q: DO YOU AGREE WITH THIS APPROACH?

A: Yes, however I encourage DTEE to provide additional information about EJ Community impacts in its next DGP, including how customers are benefitting from investments and confirming that these benefits are the ones the communities prioritize.

Q: HOW DOES DTEE USE THE GPM RESULTS?

A: The GPM helps the Company compare hundreds of vastly different types of projects and programs of different sizes. DTEE uses the GPM to identify the highest relative benefit projects that will have the greatest impact improving the grid and the overall customer experience. Investments that score highest in the GPM rankings are generally selected for the Company's distribution infrastructure strategic investment plan.[13]

Q: DOES THE GPM INCLUDE A BENEFIT-COST ANALYSIS?

A: No. The GPM compares a project's unitless benefit score to a project's cost but does not compare benefits (in dollars) to a project's cost.

Q: HOW IS THE GPM DIFFERENT FROM A BENEFIT-COST ANALYSIS?

A: The GPM helps DTEE prioritize different types of projects, while a BCA determines if customer benefits exceed customer costs for a specific project or program. A BCA will identify where (which circuits and substations) and how much of each program's spending is cost-effective (i.e., customer benefits exceed customer costs). The GPM does not identify this.

Q: WHAT IS YOUR ASSESSMENT OF THE COMPANY'S GPM?

A: First, the CEO genuinely appreciate DTEE's increased transparency and willingness to fully share the model. The GPM is complex, and I had many questions after my initial

[13] Kryscynski Direct at AJK-63:6–25.

review. DTEE hosted calls to answer questions and to help the CEO understand the methodology. I believe that the Company's application of the GPM is a reasonable approach for prioritizing DTEE's planned investments. However, as I explain later in my testimony, DTEE should expand the application of its BCA methodology to more programs to demonstrate that its planned investments are cost-effective.

Q: WHAT DO YOU RECOMMEND?

A: Because of its complexity, I recommend that DTEE conduct one or more Technical Conferences to further explain the GPM to Staff and stakeholders and how it differs from a BCA.

B. DTEE's Reliability Model

Q: WHAT IS DTEE'S RELIABILITY MODEL?

A: The Company's Reliability Model provides details of each DTEE circuit including the number of customers, overhead and underground miles, and 2017-2022 outage history. The model also calculates expected reliability improvement at a circuit level based on historical performance and the impact of planned investments on those circuits, then sums the projected performance of all circuits to provide a system level projection. The Reliability Model projects DTEE's 69% improvement in all-weather SAIDI and 34% improvement all-weather in SAIFI in 2029 that I described earlier.

Q: FROM WHICH PLANNED INVESTMENTS DOES THE COMPANY PROJECT RELIABILITY IMPROVEMENT?

A: The DTEE Reliability Model projects reliability improvements from Tree Trimming, 4.8kV Hardening, Pole Top Maintenance and Modernization ("PTMM"), 4.8kV Conversions, and Distribution Automation. The Company acknowledges that it has not

modeled other programs (URD Replacement, Cable Replacement, Breaker Replacement, Substation Risk projects) that will also reduce outage events and impact reliability.[14]

Q: HOW DOES THE MODEL CALCULATE THE RELIABILITY IMPROVEMENT PROJECTIONS FROM THESE INVESTMENTS?

A: DTEE explains that the model projects reliability performance through the following steps:

- Baseline: Calculate circuit-level baseline reliability performance.
- Program impact: Estimate impact of reliability programs.
- Degradation impact: Estimate impact of system degradation.
- Investment plan: Enter planned or expected in-service schedule for reliability programs into model.
- Calculate Ex-MED performance: Combine baseline performance with investment plan on a circuit level to project future performance.
- Calculate All-weather performance: Scale Ex-MED output to all weather output and expected ranges.[15]

Q: HOW DOES THE MODEL ESTIMATE THE IMPACT OF DTEE'S INDIVIDUAL RELIABILITY PROGRAMS?

A: DTEE's Reliability Model assumes:

- An initial 40% improvement in outage events from Tree Trimming.
- An initial 80% reduction in outage events from 4.8kV Hardening.
- An initial 90% reduction in outage events from 4.8kV Conversions.
- An initial 30% reduction in outage events from PTMM.

[14] Kryscynski Direct at AJK-73:14-16.
[15] Kryscynski Direct at AJK-70:6–17.

- Circuit-specific reductions in outage events from Distribution Automation.[16]

The model also assumes an 8% degradation in performance each year following a capital investment.[17]

Q: ARE THESE ASSUMPTIONS BASED ON ACTUAL DTEE RESULTS?

A: I understand that many of these assumptions are estimates and not based on actual DTEE results. I recommend that the Company continue to collect actual outage data to refine these assumptions.

Q: WHAT IS YOUR ASSESSMENT OF THE COMPANY'S RELIABILITY MODEL?

A: I commend the Company for disclosing this detailed circuit information and providing its projected reliability analysis. This model is the foundation of the Company's justification for its planned $9 billion of 2023-2028 capital investments, and therefore requires close scrutiny and monitoring. I understand that DTEE currently reports system-level reliability results in Case No. U-16065, but I believe the Company must report more detailed results from its individual reliability investment programs. This will allow the Commission to adjust DTEE's authorized expenditures in future proceedings if the Company is not achieving or is exceeding expected outcomes.

Q: WHAT DO YOU RECOMMEND?

A: I recommend that the Commission require DTEE to:

[16] WP AJK U-21534 Reliability Model, tab 'Benefits Walkdown & Degradation'.
[17] U-21534 MNSCDE-12.9-01 Degradation Analysis.

- Provide enhanced reporting of circuit-level reliability program results (for Tree Trimming, 4.8kV Hardening, PTMM, 4.8kV Conversions, and Distribution Automation) compared to the Company's reliability improvement projections.

I recommend that DTEE, in rebuttal testimony, confirm that it will:

- Expand the Reliability Model to include the impacts from URD Replacement, Cable Replacement, Breaker Replacement, and Substation Risk projects and include the enhanced model in its next DGP.
- Collect and incorporate actual outage data to refine the assumptions in its Reliability Model.

C. DTEE's Distribution Automation (DA) Prioritization Model

Q: WHAT IS DISTRIBUTION AUTOMATION?

A: The Company explains, "The Distribution Automation Program is primarily composed of pole top recloser deployments. Pole top reclosers . . . offer a variety of capabilities needed for distribution automation such as the ability to isolate outages into smaller sections and the ability to reroute power around damage. Reclosers installed at midpoints on a circuit will operate when a fault is detected and isolate the outage to (a) smaller area, impacting less customers. Reclosers installed at a tie point on the end of a circuit provide the ability to reconfigure circuits and reroute power around damaged sections by connecting to adjacent circuits. This device is also used to provide advanced protection capabilities, such as ground detection and isolation. . . . The pole top devices also provide circuit level SCADA monitoring and control to the System Operations Center."[18]

[18] Hartwick Direct at SMH-12:20–SMH-13:7.

Q: IS DISTRIBUTION AUTOMATION IMPORTANT FOR DTEE?

A: Yes. DA will improve ground detection and isolation, thus reducing the risk of energized downed wire on DTEE's unique ungrounded 4.8 kV delta system. DA also has the potential to be a cost-effective approach for significantly improving DTEE's reliability. As I will explain later, I recommend that DTEE apply its BCA methodology to the DA program to demonstrate cost-effectiveness.

Q: WHAT IS DTEE'S DA PRIORITIZATION MODEL?

A: The Company's DA Prioritization Model projects the circuit-level impact of DA to assist DTEE in prioritizing locations for automation investment.

Q: IS THE DA PRIORITIZATION MODEL THE SAME AS A BCA?

A; No. The model calculates benefit "points" based on reduced customer-interruptions, reduced customer-minutes interrupted, and live wire downs prevented from automation on each circuit, as well as if the circuit serves EJ or critical customers. Similar to the GPM, the model divides the benefit "points" for each circuit by the capital cost for automation to calculate a "prioritization factor." The model does not calculate the benefits (in dollars) and compare them to the costs, nor does it determine where and how much DA investment is cost-effective (i.e., customer benefits exceed customer costs).

Q: ARE THE ASSUMPTIONS FOR THE RELIABILITY IMPROVEMENT IMPACT FROM AUTOMATION BASED ON ACTUAL DTEE DATA?

A: I don't believe the assumptions are based on actual DTEE data, but rather DTEE expert opinions. In the model's tab labeled 'Assumption Sources', the source for the customer interruption impact and outage duration impact assumptions is "Confirmed in workshop with DTE Team May 18, 2023". I understand that DTEE's DA program, as currently

designed, did not begin until 2023.[19] I recommend that DTEE refresh its assumptions in the DA Prioritization Model with the actual customer interruption and outage duration impacts from automation as the actual data become available.

Q: WHAT IS YOUR ASSESSMENT OF THE DA PRIORITIZATION MODEL?

A: DTEE shared a read-only version of the model on July 9, 2024, in response to an MNSC data request.[20] I reviewed the read-only version but none of the formulas are intact, so I was unable to fully understand the model's logic and calculations.

Q: WHAT DO YOU RECOMMEND?

A: As with the GPM, DTEE's DA Prioritization Model is complex. I recommend that the Company host one or more Technical Conferences to help Staff and stakeholders understand the DA Prioritization Model's assumptions and calculations.

I also recommend that DTEE refresh its assumptions in the DA Prioritization Model with the actual customer interruption and outage duration impacts from automation as the data become available.

Finally, as I explain below, I recommend that DTEE apply its BCA methodology to its DA program to identify the circuits for which DA is cost-effective (i.e., customer benefits exceed customer costs).

[19] DTEE response to DR MNSCDE 12.8cvi.
[20] NDA CEII U-21534 MNSCDE-12.13.01 Automation Prioritization Analysis.

V. DTEE HAS DEVELOPED A BENEFIT-COST ANALYSIS METHODOLOGY

Q: HOW HAS DTEE RESPONDED TO CEO AND OTHER INTERVENOR'S REQUEST FOR A BCA METHODOLOGY?

A: DTEE engaged an external consultant to develop a BCA methodology for PTMM and Strategic Undergrounding. To calculate the benefits of an investment option, the methodology compares a "Baseline Scenario" (representing a no investment, run-to-failure scenario) with the 40-year life-cycle outcomes if the investment option is placed in service. The benefits are the avoided reactive costs,[21] avoided customer outage costs, and avoided vegetation management costs if DTEE makes the investment. The outputs of the model are the life-cycle risk-weighted present value of each investment option and the benefit-to-cost ratio ("BCR") as shown in Figure 1 below.[22]

	Baseline Scenario	Example Investment Option
Initial Investment Option Investment	**$0**	**$520,000**
Equipment Failure Reactive Cost	$325,000	$30,000
Non-Equipment Outage Reactive Cost	$125,000	$20,000
Non-Outage Trouble Reactive Cost	$25,000	$15,000
Emergent Reactive Cost Total	**$475,000**	**$65,000**
Customer Outage Cost (ICE)	**$195,000**	**$20,000**
Vegetation Management Cost	**$50,000**	**$50,000**
Total Life-Cycle Cost Excluding Initial Investment	**$720,000**	**$135,000**
Benefit (Avoided Cost)	$720,000 - $135,000 = **$585,000**	
Benefit-to-Cost Ratio for Example Investment Option	$585,000 / $520,000 = **1.125**	

Figure 1 – Example BCA Calculations[23]

[21] Reactive costs are those incurred by DTEE when responding to outages, equipment failures, or other emergencies.
[22] Exhibit A-23, Schedule M13, p. 5.
[23] *Id.*, Table 1-1.

Q: ARE THE PROJECTED EQUIPMENT FAILURE RATES IN THE PTMM BCA BASED ON ACTUAL DTEE DATA?

A: No. DTEE relied on its consultant's Weibull survivor curves[24] due to a lack of data. DTEE states, "Due to lack of historical failure data, segmented by various equipment failures as the root causes, DTEE cannot confirm whether the survivor curves assumed show higher or lower failure rates than what actually exist on the DTEE system."[25] I recommend that DTEE make the necessary modifications to its outage management system to begin collecting actual failure rate data to incorporate into its PTMM BCA.

Q: HOW DOES THE BCA QUANTIFY CUSTOMER OUTAGE COSTS?

A: The BCA uses customer outage costs calculated by the Department of Energy's Interruption Cost Estimate ("ICE") Calculator, a tool commonly used in the industry for quantifying the economic impacts of reliability improvement.

Q: ARE THERE BENEFIT TYPES NOT INCLUDED IN THE BCA?

A: The BCA model excludes benefits from improved safety and resilience.[26]

Q: COULD DTEE INCLUDE QUANTIFIABLE RESILIENCE IMPACTS?

A: Yes. Lawrence Berkeley National Laboratory ("LBNL") recently partnered with Commonwealth Edison ("ComEd") to apply its Power Outage Economics Tool ("POET") for ComEd's service territory in northern Illinois. The tool evaluates the impacts of hypothetical widespread, long-duration ("WLD") power interruption scenarios on all customer classes and evaluates the impacts of potential resilience investments. According to LBNL, "POET could be replicated in other parts of the country to estimate the costs of

[24] Weibull survivor curves project the probability of an asset surviving over time.
[25] DTEE response to DR MNSCDE 3.21.
[26] Exhibit A-23, Schedule M13, p. 5.

WLD power interruptions and the economic value of investments in power system resilience."[27] I recommend that the Company consider partnering with LBNL to apply POET to DTEE's service territory and include the benefits of improved resilience in future BCAs.

Q: WHAT COSTS ARE INCLUDED IN THE BCA METHODOLOGY?

A: The BCA methodology only includes the capital costs of the planned investments.

Q: DO YOU AGREE?

A: No. I believe the BCA should reflect the revenue requirements (including capital, lifetime O&M, financing costs, and taxes) of DTEE's planned investments. Revenue requirements reflect the full costs that customers pay for these investments, and I recommend that DTEE reflect the full revenue requirements in future BCAs.

Q: WHAT ARE THE RESULTS OF THE BCA FOR PTMM?

A: DTEE modeled the impact of PTMM on 2,242 circuits and determined that benefits exceed costs for 95% of the analyzed circuits. The circuits that have BCRs less than 1 have fewer customers and/or newer poles than the cost-effective circuits.[28]

Q: HOW DOES DTEE INTEND TO USE THESE RESULTS?

A: DTEE states, "Starting in 2025 and beyond, the (BCA) BCRs will be used during the process of selecting circuits for the PTMM program."[29]

Q: DO YOU AGREE WITH THE BCA METHODOLOGY?

A: I believe the BCA methodology is a good first step and applicable to many more of DTEE's programs (e.g., 4.8 kV Conversions, Distribution Automation, etc.). The Company can

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[27] https://eta-publications.lbl.gov/sites/default/files/puct_ice-poet_larsen_28jul2023.pdf
[28] Exhibit A-23, Schedule M13, p. 22.
[29] DTEE response to DR MNSCDE 3.8(a).

further refine the BCA methodology by incorporating actual DTEE failure data (when available), potentially incorporating resilience benefits, and including full revenue requirements.

Q: WHAT DO YOU RECOMMEND?

A: I recommend DTEE confirm, in rebuttal testimony, it will:

- Expand its application of the BCA methodology to its 4.8kV Conversion, Distribution Automation, Frequent Outage, Subtransmission Redesign & Rebuild, Breaker Replacement, URD Replacement, Cable Replacement, and Tree Trimming Surge programs.
- Make necessary modifications to its outage management systems to begin incorporating actual DTEE failure data in the BCA methodology.
- Consider partnering with LBNL to quantify the resilience impacts of DTEE's planned investments using POET, for inclusion in future BCAs.
- Modify the BCA methodology to reflect the full revenue requirements of investments.

VI. ALTERNATIVES FOR TRANSFORMING DTEE's DISTRIBUTION SYSTEM

Q: WHY ARE NON-CONVENTIONAL SOLUTIONS IMPORTANT FOR DTEE?

A: DTEE's customers are facing a $9 billion price tag between now and 2029 to transform the distribution grid using conventional grid solutions. Non-conventional solutions can potentially be more cost-effective for addressing grid needs, since many of these alternatives use customer-owned and customer-financed resources, lowering the overall cost. They can be quickly deployed and flexibly scaled to meet grid needs that may vary

over time. These non-conventional solutions can potentially offset some of DTEE's planned Reliability and System Loading capital expenditures.

Q: WHAT IS SYSTEM LOADING?

A: System loading refers to the peak amount of delivered energy relative to the rated capacity of the distribution equipment used to deliver the energy. If peak demand exceeds a component's rating, the component is overloaded.

Q: WHAT ARE DTEE'S SYSTEM LOADING EXPENDITURES?

A: DTEE explains, "In areas that have seen and continue to see steady load growth, capital investments are required to prevent (equipment) overloads. These projects are categorized as System Loading projects."[30] DTEE projects its System Loading capital expenditures to grow from $33 million in 2024 to $79 million in 2025.[31]

Q: WHAT ARE EXAMPLES OF NON-CONVENTIONAL SOLUTIONS?

A: Non-conventional solutions can include:

- **Conservation Voltage Reduction ("CVR")/Volt-Var Optimization ("VVO")** - CVR maintains customer voltage at the circuit level in the lower portion of the allowable voltage ranges, thus reducing system losses, peak demand and energy consumption. VVO manages system-wide reactive power flow to reduce losses, manage circuit level voltage, and/or optimize power factors.[32] One main advantage of CVR/VVO is that it requires no customer behavioral change to achieve significant energy and peak demand reductions.

[30] Deol Direct at SSD-81:19–21.
[31] U-21534 Capital Exhibits A-12 B5.4 DO, tab 'A-12 B5.4 Redesign', cells G149 and H149.
[32] Hartwick Direct at SMH-48:15–23.

- **Geo-targeted Energy Waste Reduction ("EWR") and Demand Response ("DR")** - Unlike conventional EWR and DR programs which provide system-wide energy reductions or load relief at the time of system peaks, geo-targeted EWR/DR programs provide energy and peak demand reductions to address local circuit or substation overloads.
- **Utility-scale Solar + Storage, and Stand-Alone Storage** - The addition or inclusion of large-scale storage alone or in a portfolio with utility-scale solar facilities (>1 MW) to address capacity, reliability, and power quality issues. New technologies such as Long Duration Energy Storage can discharge or charge for days at a time, providing new ways to support distribution system resilience.
- **Microgrids** - A group of interconnected loads and DER that acts as a single controllable entity with respect to the grid. Microgrids can connect and disconnect from the grid to operate in grid-connected or island mode. Microgrids can improve customer reliability and resilience to grid disturbances.[33] DTEE is also testing the concept of Adaptive Networked Microgrids ("ANM"), which are two or more neighboring microgrids with controls and protection that enable them to merge based on several considerations including but not limited to the locations of faults, load forecasts, weather forecasts, and DER status. These microgrids can dynamically change their boundaries through switching operations to isolate faults and improve customer reliability.[34]

[33] https://www.nrel.gov/grid/microgrids.html
[34] Hartwick Direct at SMH-75:7–12.

- **Virtual Power Plants ("VPPs")** - According to the DOE, VPPs are aggregations of customer-owned DER such as rooftop solar with behind-the meter ("BTM") batteries, electric vehicles and chargers, electric water heaters, smart buildings and their controls, and flexible commercial and industrial loads that can balance electricity demand and supply and provide utility-scale and localized grid services. VPPs enroll DER owners—including residential, commercial, and industrial electricity consumers—in a variety of participation models that offer rewards for contributing to efficient grid operations.[35]

Q: DOES DTEE HAVE EXPERIENCE WITH THESE NON-CONVENTIONAL SOLUTIONS?

A: Yes. The Company is scaling up its deployment of CVR/VVO. As shown in Figure 2 below, DTEE also has a suite of NWA pilots which are testing combinations of these technologies for various use cases. However, I believe the Company's NWA pilots primarily rely on DTEE-owned assets. The Company will gain experience with non-conventional solutions utilizing customer-owned DER with its Veridian NWA pilot.

Location	Technology	Pilot Scope and Objectives	'23-'25 Cost (M)[36]
Hancock Substation	Geo-targeted EWR	Test the effectiveness of targeted EWR programs to address substation loading; the pilot, completed in 2020, achieved 57kW of peak reduction or approximately 141% of the goal.[37]	N/A
Fisher Substation	Geo-targeted EWR/DR	Targeted deployment of DR and EWR to relieve a portion of circuit/substation overloads.	$4.7

[35] US Department of Energy, *Pathways to Commercial Liftoff: Virtual Power Plants*, September 2023, p. 2. https://liftoff.energy.gov/wp-content/uploads/2023/10/LIFTOFF_DOE_VVP_10062023_v4.pdf
[36] U-21534 Capital Exhibits A-12 B5.4 DO, tab 'A-12 B5.4 Tech'.
[37] MPSC Case No. U-20836, Pfeuffer Direct at SGP-143:4–SGP-144:5.

		Expecting an estimated 300 peak-kW reduction over the span of three years, to be completed in 2025."38	
Port Austin Substation	Utility-scale Solar + Storage	Solar + storage to address substation and circuit overloads, low voltage during periods of peak demand, and backup power during severe weather.39 Site construction and equipment installation to be completed by early 2025.	$5.1
O'Shea Solar Park	Utility-scale Solar + Storage	1 MW by 1 MWh Battery Energy Storage System ("BESS") at the O'Shea Solar Park, a DTEE owned 2 MW solar array. DTEE expects the BESS to address power quality concerns related to the intermittent nature of the installed solar generation.[40] BESS installation to be completed in late 2024.	$0.9
Port Austin Substation O'Shea Solar Park	Microgrids	DTE Electric will use DOE funding to incorporate Adaptive Networked Microgrids (ANMs) to further increase the customer benefits from the deployed assets. Between these two locations, DTEE will fully develop and test the ANM concept to identify customer benefits.[41] DTEE expects ANM pilot results in 2028.	$14.4 (net of project contributions)
Veridian	VPP	DTEE control of residential BTM customer-owned solar and storage to prevent overloads.[42]	$8.8

Figure 2 – Select DTEE NWA Pilots

[38] Hartwick Direct at SMH-59:3–SMH-60:8.
[39] Hartwick Direct at SMH-61:19–SMH-62:5.
[40] Hartwick Direct at SMH-55:7–12.
[41] Hartwick Direct at SMH-73:17–SMH-74:5.
[42] Hartwick Direct at SMH-62:24–SMH-63:20.

Q: PLEASE DESCRIBE DTEE'S EXPERIENCE WITH CVR/VVO.

A: DTEE piloted CVR/VVO on six circuits in 2020 through 2022 and achieved peak reductions of 0.9% to 1.4% and energy savings of 0.7% to 1.0%. The Company now plans to upgrade a total of 44 circuits in 2024-2025 to enable CVR/VVO. The program ($12.3 million from 2023-2025) is targeting a total peak demand reduction of up to 38 MW by 2030.[43]

Q: WHY IS DTEE FOCUSED ON MICROGRIDS?

A: The Company states, "The DOE's vision includes microgrids as a building block for the future electrical system. Microgrids provide a mechanism to bring local DER together to provide solutions for resilience and reliability by becoming their natural aggregation point. Microgrids form a unit that hosts loads and generation that can be connected or disconnected from the rest of the grid. Additionally, multiple neighboring microgrids with dynamic boundaries can form larger multi-customer dynamic microgrids."[44]

Q: WHAT DOES DTEE CONSIDER TO BE THE CUSTOMER BENEFITS OF MICROGRIDS?

A: DTEE states, "Benefits to the Company's customers include (a) greater resilience to extreme weather conditions, (b) improved reliability for everyday operations, (c) enhanced security from an evolving number of cyber-physical threats, (d) superior flexibility to respond to the variability and uncertainty of conditions, and (e) increased sustainability through energy efficient and renewable resources."[45]

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[43] Hartwick Direct at SMH-49:10–SMH-50:24.
[44] Hartwick Direct at SMH-74:13–19.
[45] Hartwick Direct at SMH-76:1–5.

Q: HOW ARE UTILITIES DEPLOYING VPPS?

A: Utilities use VPPs (managed either in-house or by a third party) for a broad range of use-cases, including as an alternative to procuring energy or capacity from wholesale markets, to alleviate overloaded distribution systems, to build resilience for their customers, and to avoid renewables curtailment.[46]

Q: PLEASE PROVIDE AN EXAMPLE OF A SUCCESSFUL VPP.

A: ConnectedSolutions is a New England VPP operated by multiple utilities with support from VPP platform company EnergyHub,[47] in which residential and non-residential customers can enroll a variety of DERs. In Massachusetts, Connecticut, and Rhode Island, utilities offer customers a bring-your-own-battery demand response program. In addition to the customer-owned battery providing power backup services, the program links the batteries to create a VPP that the utilities use to curb peak demand and provide additional grid services. Battery owners who participate in the ConnectedSolutions program earn a one-time incentive for enrolling (up to $3,000 in some states)[48] and additional income for every kilowatt of benefit they provide to the grid—up to $1,500 per year depending on the size of the battery and the state where they live.[49]

Q: WHO TYPICALLY ENROLLS PARTICIPANTS AND AGGREGATES THE DER IN A VPP?

A: According to the DOE, three primary models have emerged.

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[46] US Department of Energy, *Pathways to Commercial Liftoff: Virtual Power Plants*, September 2023, p. 20. https://liftoff.energy.gov/wp-content/uploads/2023/10/LIFTOFF_DOE_VVP_10062023_v4.pdf.
[47] https://www.energyhub.com/
[48] https://www.eversource.com/content/residential/save-money-energy/energy-efficiency-programs/demand-response/battery-storage-demand-response/home-battery-storage-faqs/nh
[49] https://www.energyhub.com/blog/energyhub-and-tesla-to-support-the-northeasts-largest-battery-virtual-power-plant/

1) The entity responsible for enrolling DER-owning customers is a utility that serves their electrical load. In this scenario, the utility will reach out to customers and offer to enroll their existing DER and/or offer DER purchase subsidies as enrollment incentives. Utilities who aggregate DER of their own customers may operate the VPP in-house or partner with a third-party service provider to operate the VPP. ConnectedSolutions described above is an example of the third-party service provider operating the VPP.

2) The manufacturer or retailer of the DER who sold it to the customer takes responsibility for enrollment and management of customers. DER companies that have launched VPP platforms include EV makers Tesla, Ford, and GM, and distributed solar and storage companies Sunrun and Sunnova.

3) A VPP platform company enrolls and manages DER, which may include multiple different types and brands aggregated into a single portfolio. EnergyHub, Voltus, AutoGrid, and Leap, for example, recruit participants, directly or via partnerships, with a variety of DER in residential and non-residential settings.[50]

Q: WHAT DO YOU RECOMMEND?

A: I recommend that the Commission require DTEE work with Staff and stakeholders to design a VPP pilot/demonstration[51] for resilience and peak load reduction use-cases using a third-party aggregator, and to include the pilot/demonstration in its 2025 DGP.

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[50] US Department of Energy, *Pathways to Commercial Liftoff: Virtual Power Plants*, September 2023, p. 16. https://liftoff.energy.gov/wp-content/uploads/2023/10/LIFTOFF_DOE_VVP_10062023_v4.pdf.

[51] Pilots are typically focused on answering technical questions, while demonstrations validate the business case for scaling up to full system deployment and can test business models, rates/incentives, customer interest, and cost-effectiveness.

VII. DTEE MUST MOVE MORE QUICKLY FROM PILOTS TO FULL DEPLOYMENT

Q: WHAT IS DTEE'S VISION FOR NWA OR NON-CONVENTIONAL SOLUTIONS?

A: DTEE explains, "The Company's objective is to incorporate NWA solutions into the distribution planning process to be considered along with traditional options to best meet the customer needs. . . . The pilots currently being pursued are building blocks that will form a foundation for future NWA projects. As capabilities are confirmed, multiple NWA technologies can be combined to further advance the Company's utilization of NWA."[52]

The Company further explains, "NWA projects have the potential to become economic alternatives compared to traditional infrastructure upgrades. The pilots are expected to validate customer and economic benefits to help further refine the analysis of NWAs as an alternative to traditional solutions. While individual participating customers benefit from investment in some of the technologies used in targeted NWA solutions, such as lower energy bills due to EWR, customers overall may benefit from the deferred or displaced investment in infrastructure."[53]

Q: DO YOU SUPPORT THIS APPROACH?

A: Yes. I agree that these are important building blocks for future DTEE planning and operating capabilities, and I recommend that the Commission approve these pilots.

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[52] Hartwick Direct at SMH-52:21–SMH-53:2.
[53] Hartwick Direct at SMH-53:5–11.

Q: HAS DTEE EXPLAINED HOW IT WILL SCALE UP THESE PILOTED TECHNOLOGIES AND INCORPORATE NWA SOLUTIONS INTO ITS DISTRIBUTION PLANNING PROCESS?

A: No. DTEE did not explain it in its most recent DGP[54] and has not addressed it in this proceeding. Non-conventional solutions are an important component of the future grid and DTEE, while off to a good start with the pilots, should do more to define actionable next steps to move from pilots to demonstrations to full deployment.

As the Smart Electric Power Alliance explains, "Replicability and scalability are not just a matter of taking a small project and expanding it. (Utilities) should have a clear plan for how to fully deploy their solution that leverages the work completed during the pilot process. The risk to the pilot program if replicability and scalability are not addressed is failure to act on the results of the pilot creating frustration for all stakeholders involved."[55]

Q: WHAT SHOULD DTEE DEFINE?

A: With full deployment in mind, DTEE should identify and plan for the strategic, technical, and economic barriers to scaling from the outset of each pilot project.[56] DTEE should define how it will incorporate lessons-learned from the pilots, the cost/timing thresholds and evaluation criteria the Company intends to employ to determine whether an NWA may

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[54] MPSC Case No. U-20147, Comments on DTE Electric's 2023 Electric Distribution Grid Plan Submitted by the Ecology Center, the Environmental Law & Policy Center, Union of Concerned Scientists, & Vote Solar, March 15, 2024, pp. 23–26.

[55] Smart Electric Power Alliance, *Guidelines for a Successful Grid Modernization Pilot Project Program*, 2019, p. 13. https://sepapower.org/resource/pilot-projects-guidelines-for-a-successful-grid-modernization-pilot-project-program/

[56] Rocky Mountain Institute, *Pathways for Innovation - The Role of Pilots and Demonstrations in Reinventing the Utility Business Model*, 2017, p. 21. https://rmi.org/insight/pathways-for-innovation/

be an appropriate solution for a projected grid need, as well as the solution-sourcing process DTEE will use to solicit NWA proposals from the market.

Q: WHAT DO YOU RECOMMEND?

A: I recommend that the Commission require DTEE to work with Staff and interested stakeholders to define its approach for scaling up piloted technologies and incorporating NWA solutions into its distribution planning process. DTEE should explain the approach in its next DGP.

VIII. SUMMARY OF RECOMMENDATIONS

Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A: I recommend that the Commission require DTEE to:

1) Provide enhanced reporting of circuit-level reliability program results (for Tree Trimming, 4.8kV Hardening, PTMM, 4.8kV Conversions, and DA) compared to the Company's reliability improvement projections.

2) Work with Staff and interested stakeholders to design a VPP pilot/demonstration project for resilience and peak load reduction use-cases using a third-party aggregator, and to include the pilot/demonstration in its 2025 DGP.

3) Work with Staff and interested stakeholders to define its approach for scaling up piloted technologies and incorporating NWA solutions into its distribution planning process. DTEE should explain the approach in its next DGP.

I also request that DTEE, in rebuttal testimony, confirm that it will:

1) Provide additional information about EJ Community impacts in its next DGP, including how customers are benefitting from investments and confirming that these benefits are the ones the communities prioritize.

2) Conduct one or more Technical Conferences to further explain its GPM to Staff and stakeholders and explain how it differs from a BCA.

3) Conduct one or more Technical Conferences to help Staff and stakeholders understand the DA Prioritization Model's assumptions and calculations.

4) Expand its Reliability Model to include the impacts from URD Replacement, Cable Replacement, Breaker Replacement, and Substation Risk projects and include the enhanced model in its next DGP.

5) Collect and incorporate actual outage data to refine the assumptions in its Reliability Model.

6) Refresh its assumptions in the DA Prioritization Model with the actual customer interruption and outage duration impacts from automation as the data become available.

7) Expand the Company's application of its BCA methodology to its 4.8kV Conversion, Distribution Automation, Frequent Outage, Subtransmission Redesign & Rebuild, Breaker Replacement, URD Replacement, Cable Replacement, and Tree Trimming Surge programs.

8) Make necessary modifications to its outage management systems to begin incorporating actual DTEE failure data in its BCA methodology.

9) Consider partnering with LBNL to quantify the resilience impacts of DTEE's planned investments using POET, for inclusion in future BCAs.

10) Modify its BCA methodology to reflect the full revenue requirements of investments.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

JUDGE WALLACE: Can you guys give me a second here. I'll be right back.

(At 10:06 a.m., brief pause.)

JUDGE WALLACE: O.K. Sorry about that. All right. Mr. Abrams, please proceed.

MR. ABRAMS: At this time, on behalf of the Clean Energy Organizations and by stipulation of the parties, I move to bind in the Direct Testimony of Boratha Tan, consisting of a cover page, a table of contents, and 15 pages of questions and answers, and I move for the admission of Exhibit CEO-6 through CEO-8.

JUDGE WALLACE: All right. Is there any objection to binding in the direct testimony of Mr. Tan?

Hearing none, the testimony is bound in.

Is there any objection to the admission of Exhibits CEO-6 through CEO-8?

Hearing none, those exhibits are admitted.

(Testimony Bound In.)

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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

DIRECT TESTIMONY OF

BORATHA TAN

ON BEHALF OF

THE ECOLOGY CENTER, THE ENVIRONMENTAL LAW & POLICY CENTER, UNION OF CONCERNED SCIENTISTS, AND VOTE SOLAR

July 26, 2024

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I. WITNESS IDENTIFICATION

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is Boratha Tan. My business address is 1 S. Dearborn St, Chicago, IL 60603. However, I work remotely from home in Detroit, MI.

Q: BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A: I serve as Regulatory Manager, Midwest for Vote Solar. I oversee policy development and implementation related to large scale and distributed solar generation in the region. I also review regulatory filings, perform technical analyses, and testify in commission proceedings on issues relating to solar generation.

Vote Solar is an independent 501(c)3 nonprofit working to repower the U.S. with clean energy by making solar power more accessible and affordable through effective policy advocacy. Vote Solar seeks to promote the development of solar at every scale, from distributed rooftop solar to large utility-scale plants. Vote Solar has over 90,000 members nationally, including over 2,700 members in Michigan. Vote Solar is not a trade organization, nor does it have corporate members.

Q: ON WHOSE BEHALF ARE YOU SUBMITTING THIS DIRECT TESTIMONY?

A: I appear here in my capacity as an expert witness on behalf of the Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar. I refer to these parties collectively in this case as the Clean Energy Organizations or "CEO."

Q: PLEASE SUMMARIZE YOUR QUALIFICATIONS, EXPERIENCE, AND EDUCATION.

A: I graduated from Villanova University, with a Bachelor of Science in Mechanical Engineering and a minor in Peace and Justice. I worked at Ford Motor Company for six

years in various capacities within the Electrical Systems Engineering department of the company; my work included designing, prototyping, and testing various high voltage components for future electric vehicles. My team and I have a pending patent on AI-related tools for electric motors. I also graduated with a Master's in Public Policy from the University of Michigan. I have experience in different engineering and analysis tools, including Autodesk, MATLAB, Ansys, RStudio, and Stata. My resume is attached as Ex. CEO-6.

Q: HAVE YOU TESTIFIED BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION?

A: Yes. I provided direct testimony in the DTE Electric Company (the Company, or DTE) 2022 Integrated Resource Plan before the Michigan Public Service Commission[1] (the Commission, or MPSC), as well as the DTE Electric 2023 Rate Case.[2] I have also provided direct testimony in the Consumers Energy 2023 Electric Rate Case.[3] Finally, I have provided comments in various MPSC dockets with the CEO, which can be found in my resume.

Q: HAVE YOU TESTIFIED OR PROVIDED COMMENTS IN SIMILAR STATE REGULATORY PROCEEDINGS?

[1] Direct Testimony of Boratha Tan on behalf of the Clean Energy Organizations, *In the matter of the application of DTE Electric Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief,* Michigan Public Service Commission Docket No. U-21193, March 9, 2023.
[2] Direct Testimony of Boratha Tan on behalf of the Clean Energy Organizations, *In the matter of the application of DTE Electric Company for approval to increase its rates, and for other relief,* Michigan Public Service Commission Docket No. U-21297, June 13, 2023.
[3] Direct Testimony of Boratha Tan on behalf of the Clean Energy Organizations, *In the matter of the application of Consumers Energy Company for approval to increase its rates, and for other relief,* Michigan Public Service Commission Docket No. U-21389, August 29, 2023.

A: Yes. I provided direct testimony in the Commonwealth Edison Company (ComEd) Multi-Year Integrated Grid Plan and the Ameren Illinois Multi-Year Integrated Grid Plan before the Illinois Commerce Commission.[4]

Q: ARE YOU SPONSORING ANY EXHIBITS?

A: Yes; my exhibits are outlined below.

- Exhibit CEO-6: Resume of Boratha Tan
- Exhibit CEO-7: U-21534 Discovery CEODE-1.6
- Exhibit CEO-8: U-21534_RCode.txt

II. PURPOSE OF TESTIMONY AND SUMMARY

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The purpose of my testimony is to describe the benefits of regression analysis, summarize my testimony and the Commission's order in the 2023 DTE Rate Case U-21297 with respect to using regression analysis on reliability data, summarize subsequent meetings with DTE and Commission Staff on regression, and provide one additional regression analysis on DTE's 2023 reliability data, which is an update to the regression analysis I conducted in DTE's prior case.

III. REGRESSION ANALYSIS BASICS

Q: WHAT IS REGRESSION ANALYSIS?

A: Regression analysis is a statistical model/method used to examine the relationship between a "dependent variable" and one or more "independent variables". Regression analysis is

[4] Direct Testimony of Boratha Tan on behalf of the Joint NGOs, *Order Requiring Commonwealth Edison Company to file an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act.,* Illinois Commerce Commission Docket No. 22-0486, May 22, 2023. *Ameren Illinois Company*… Illinois Commerce Commission Docket No. 22-0487, May 13, 2024.

used to understand how these independent variables can predict (or influence) the outcome of the dependent variable.

Q: WHAT ARE SOME BENEFITS TO REGRESSION ANALYSIS GENERALLY?

A: There are many benefits to regression analysis. For example, regression helps researchers and policymakers understand the relationships between variables; understanding these relationships helps identify social and structural predictors that influence outcomes. Regression is also governed by statistical techniques that determine the "fit" of the model. In other words, a regression model would determine if certain independent variables are statistically significant enough to be correlated to the dependent variable.

Q: WHY IS REGRESSION ANALYSIS IMPORTANT TO UNDERSTANDING THE GRID?

A: Regression is important in this context because the analysis allows us to interpret reliability metrics with external data, that would otherwise be excluded when observing said reliability metrics alone. One benefit to utilizing regression analysis includes understanding the relationship between the dependent variable (i.e. reliability metrics) and independent variables (such as characteristics of the grid and demographic information of electric customers). These relationships can be revealed based on various available data, and DTE can use regression analysis to better understand how customers experience the grid's reliability.

IV. <u>SUMMARY OF REGRESSION ANALYSIS IN U-21297 RATE CASE</u>

Q: CAN YOU SUMMARIZE YOUR TESTIMONY IN THE U-21297 DTE RATE CASE?

A: In my U-21297 testimony, I described the benefits of regression analysis, I summarized the Company's reliability analysis presented by DTE Witness Allen J. Kryscynski, and I offered my own regression model that analyzes grid reliability as a function of various demographic data.[5] In summary, my regression analysis found in 2021 and 2022 that more densely populated communities experienced fewer minutes of service interruption, while more BIPOC and higher income communities experienced more minutes of service interruptions.

My findings are discussed below, in "Section VI. Regression Analysis with 2023 Reliability Data" of this testimony.

Q: WHAT WAS THE COMMISSION'S ORDER IN CASE U-21297 AS IT PERTAINS TO REGRESSION ANALYSIS?

A: In the Commission's December 1, 2023, order for case U-21297, the Commission ordered:

> DTE Electric Company shall also work with the Commission Staff and stakeholders to develop a detailed regression analysis of customer demographics and reliability for vulnerable communities to be used in the company's distribution plan case. DTE Electric Company shall also provide the data supporting the regression analysis to enable interested parties to perform their own analyses.[6]

The Company, following this order, reached out to all interested parties surrounding regression analysis, including the CEO, Detroit Area Advocacy Organizations (DAAO), and the MPSC Staff. DTE then set up a meeting with the CEO to kick off discussions around running and implementing regression analysis. DAAO did not participate in these meetings due to their limited availability but spoke to the CEO about improving the analysis to satisfy the Commission's order.

[5] Case No. U-21297, Direct Testimony of CEO Witness Boratha Tan (June 13, 2023).
[6] U-21297, Commission Order December 1, 2024, on page 375.

V. MEETINGS WITH DTE AND MPSC STAFF

Q: HOW MANY MEETINGS DID YOU HAVE WITH DTE?

A: The CEO met with the Company three times to discuss regression analysis. The first meeting was on February 23, 2024. The second meeting was held on April 16, for both CEO and MPSC Staff. The third meeting was held on May 15, for both CEO and MPSC Staff.

Q: WHAT WAS THE PURPOSE OF THESE MEETINGS?

A: These meetings brought together DTE, CEO, and MPSC Staff to review regression modeling basics, discuss available or attainable data, and determine which data sets were relevant to running a regression analysis.

Specifically, DTE, CEO, and MPSC Staff discussed the Company's data around grid characteristics. These characteristics included overhead and underground lines, most recent tree-trim year, most recent pole top maintenance and modernization (PTMM) year, and circuit loading. These characteristics drive at the age and condition of the grid and can help show the effect of system upgrades on reliability across different demographics. More importantly, these characteristics are already key drivers that the Company tracks as part of maintaining the distribution grid. In the most recent meeting, DTE committed to working with these grid characteristics and its reliability data to run a preliminary regression model.

Q: WHAT ARE YOUR THOUGHTS ON THE PROGRESS MADE SO FAR IN THESE MEETINGS?

A: I am pleased that the parties have worked together constructively and have made progress towards a preliminary analysis, but there is more work yet to do. I believe that using regression analysis for understanding the grid is necessary in both the distribution grid

plans and in rate cases. Because DTE has filed rate cases annually, these dockets allow for intervenors, such as the CEO, to promptly monitor and address any progress that the Company makes in terms of reliability improvements.

Setting up the required files and codes to run an initial regression analysis is the most tedious part; once the regression is set up, it is relatively easy to update and improve the regression model with new data in subsequent proceedings. After establishing a regression framework, DTE must integrate the analyses and findings into its processes. The CEO look forward to engaging with the Company on this important work.

However, I wish to express the CEO's desire to continue working with the MPSC Staff and DTE in reviewing the Company's initial regression analysis. Additionally, the CEO look forward to swiftly discussing regression analysis improvements with DTE and the MPSC Staff before the next distribution grid plan case.

VI. REGRESSION ANALYSIS WITH 2023 RELIABILITY DATA

Q: DID DTE RUN ANY REGRESSION ANALYSIS IN THIS CASE?

A: No, they did not. However, this is understandable because the Company submitted its application in this Rate Case on March 28, 2024, and had only met with the CEO a month before that time. Additionally, DTE did not have its grid characteristics data prepared in time for this rate case.[7]

Q: DID YOU RUN A REGRESSION ANALYSIS FOR THIS CASE?

A: Yes, I did. I improved upon my analysis from case U-21297 by replacing area median income with median home price. In that case, I analyzed the Company's reliability metrics (SAIDI, SAIFI, and CAIDI) against various demographic data aggregated to census tracts.

[7] Ex. CEO-7, U-21534 Discovery CEODE-1.6.

These demographics included population density, percentage BIPOC population, area median income, median age, and percent of population in poverty. All of the demographic information is pulled from the American Community Survey's 5-year average.

SAIDI stands for "System Average Interruption Duration Index", which means the total number of minutes of interruption the average customer experiences. SAIFI stands for "System Average Interruption Frequency Index", which means how often the average customer experiences an interruption. Company Witness Allen J. Kryscynski also provides "all-weather (AW), or major event day (MED)" and "excluding MED" indices. According to the Witness, AW or MED stands for "any 24-hour period in which there is a significant statistical difference in daily SAIDI".[8]

Q: CAN YOU BRIEFLY DESCRIBE WHAT YOUR REGRESSION ANALYSIS FOUND IN CASE U-21297?

A: In case U-21297, my analysis showed that more dense communities (or census tracts) saw improving SAIDI (i.e. reduced minutes of service interruption). However, more heavily BIPOC and higher income communities experienced worse SAIDI (more minutes of service interruption). Please see Table 1 (4th regression model) below for all weather SAIDI results.

[8] Direct Testimony of Allen J. Kryscynski on behalf of DTE *In the matter of the application of DTE Electric Company for approval to increase its rates, and for other relief,* Michigan Public Service Commission Docket No. U-21534, March 28, 2024, at 18.

Table: 2021-22 AW SAIDI, Multivariate A

	Dependent variable:			
	AW_SAIDI			
	(1)	(2)	(3)	(4)
log(pop_density + a)	-102.839***	-96.384***		-120.487***
	(13.032)	(12.503)		(13.576)
nonwhitepercent	1.777***		0.617	2.881***
	(0.549)		(0.598)	(0.643)
ami		0.909	12.329**	12.279**
		(4.610)	(5.319)	(5.250)
Constant	671.491***	737.765***	650.677***	547.992***
	(26.488)	(36.254)	(55.198)	(55.695)
Observations	2,980	2,932	2,932	2,932
R^2	0.021	0.021	0.002	0.028
Adjusted R^2	0.020	0.021	0.001	0.027
Residual Std. Error	860.658 (df = 2977)	862.548 (df = 2929)	871.095 (df = 2929)	859.756 (df = 2928)
F Statistic	31.158*** (df = 2; 2977)	31.934*** (df = 2; 2929)	2.711* (df = 2; 2929)	28.112*** (df = 3; 2928)
Note:				*p<0.1; **p<0.05; ***p<0.01

Table 1: DTE 2021-2022 AW SAIDI Regression Analysis, from case U-21297

In this current rate case, my regression analysis features SAIDI and SAIFI as the dependent variables, and population density, percentage BIPOC population, and median home price as independent variables. I removed the other variables from this analysis to simplify the model and interpretations.

With this new regression iteration, I want to explore if the listed demographic information is correlated with DTE's 2023 reliability data.

Q: WHY ARE YOU RUNNING REGRESSION ANALYSIS IN THIS CASE?

A: There are three main reasons why I am running an updated iteration of my regression analysis:

1. As stated earlier, regression analysis is better than observing reliability averages alone because this analysis allows for demographic data to be included for understanding reliability differently.
2. I want to demonstrate how regression analysis can be improved with updated data and processes.
3. Regression analysis, when iterated on itself, is a good tool to benchmark grid reliability over time.

Q: FOR THIS REGRESSION ITERATION, WHY DID YOU SELECT POPULATION DENSITY, PERCENT BIPOC POPULATION, AND MEDIAN HOME PRICE AS VARIABLES FOR YOUR REGRESSION MODELING?

A: Both population density and median home price can be good proxies to understanding the grid. In very urban (densely populated) areas, the circuit and grid topology is different from more rural areas. Median home price replaces area median income because it is a better proxy for wealth; area median income can be skewed for areas in/around colleges and retirement facilities where students and retirees (who may or may not have wealth) live. Similarly, areas with very expensive homes could hint at newer or upgraded circuits that connect these homes to the grid.

Having these proxies is important because they substitute for the grid topology and circuit data that was not available in time for this case. The model will more accurately depict the relationship between grid topology and demographic data once DTE provides the data and takes over running the analyses.

Percent BIPOC population is chosen to determine if certain customers experienced outages in 2023 differently if one community has more BIPOC residents than other communities.

Q: WHAT DID YOU FIND IN YOUR ANALYSIS?

A: For all-weather (AW) SAIDI, when we look at a regression model with population density, percent BIPOC, and median home price included, we found:

- Holding percent BIPOC and median home price constant, a one percent increase in population density is associated with a SAIDI decrease of 148. In other words, a census tract with increasing population density can experience 148 fewer minutes of interruption.
- Holding population density and median home price constant, a one percent increase in BIPOC population is associated with a SAIDI increase of 3.5. In other words, a census tract with increasing BIPOC population can experience 3.5 more minutes of interruption. Note: the BIPOC variable was calculated to be from 0 to 100%, so the variable seen in Table 1 shows 351 SAIDI minutes. This means that for a census tract with 100% BIPOC population, this community experienced 351 additional minutes of interruption.
- Holding population density and percent BIPOC population constant, a $10,000 increase in median home price is associated with a SAIDI increase of 15. In other words, a census tract with increasing median home price sees 15 more minutes of interruption. Note: the median home price variable was calculated in $10,000 increments rather than single dollars.

Please see Table 2 for the details of the 2023 AW SAIDI regression modeling.[9]

[9] For my complete regression results, please see and run Ex. CEO-8, U-21534_RCode.txt

Table: 2023 AW SAIDI, Multivariate

	Dependent variable:			
	`AW SAIDI`			
	(1)	(2)	(3)	(4)
log(pop_density + a)	-125.392***	-116.818***		-147.769***
	(19.865)	(17.439)		(20.394)
bipoc	-76.127		-101.614	351.382***
	(105.333)		(103.396)	(120.313)
Homevalue		12.269***	13.120***	14.973***
		(1.895)	(2.104)	(2.107)
Constant	1,107.476***	800.394***	887.091***	608.638***
	(48.342)	(53.702)	(76.027)	(84.793)
Observations	4,478	4,389	4,389	4,389
R^2	0.014	0.022	0.013	0.024
Adjusted R^2	0.013	0.022	0.012	0.024
Residual Std. Error	1,785.417 (df = 4475)	1,787.443 (df = 4386)	1,796.365 (df = 4386)	1,785.911 (df = 4385)
F Statistic	30.763*** (df = 2; 4475)	50.429*** (df = 2; 4386)	28.199*** (df = 2; 4386)	36.520*** (df = 3; 4385)
Note:				*p<0.1; **p<0.05; ***p<0.01

Table 2: DTE 2023 AW SAIDI Regression Analysis

One additional observation to note is that increasing median home price is correlated with increasing SAIDI (longer duration of interruption). There may be a couple of reasons that explain this:

1. The higher priced homes are located in the suburbs and other towns with low urban density and high concentration of trees overhanging electric lines;
2. Even though newer condominiums and single-family properties are more expensive and currently concentrated in downtown Detroit, there aren't enough new builds to substantially show a shift for installing new wires and poles;
3. There might be additional factors related to the home that could be correlated with reliability, such as average age of the housing stock or average square footage.

Please see below for a map of median home price in Southeast Michigan, aggregated to census tracts (Figure 1). Each of these potential explanations could be explored in subsequent and more sophisticated regression analyses.

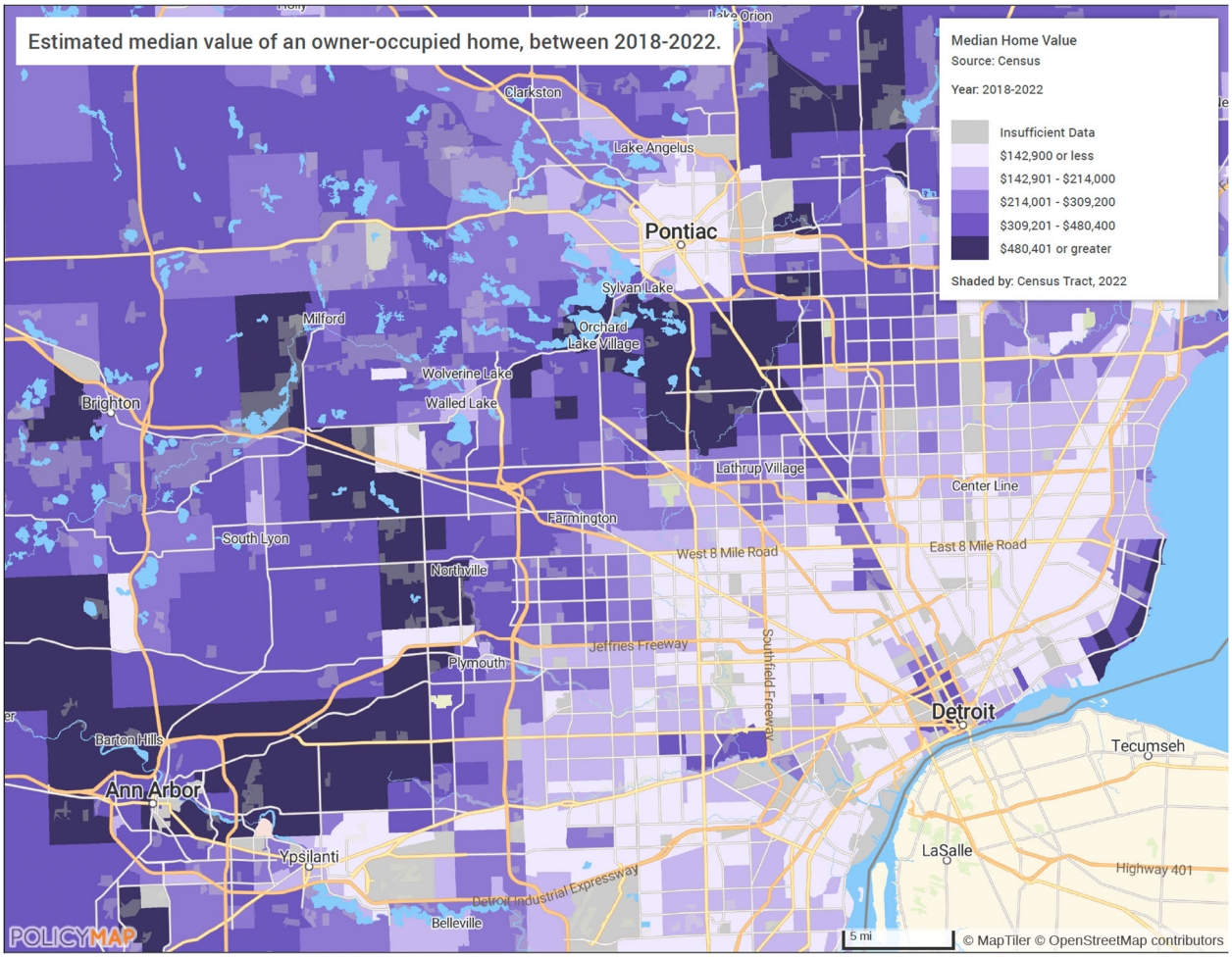


Figure 1: Median Home Value in Southeast Michigan

Q: CAN YOU COMPARE THE OBSERVATIONS YOU FOUND BETWEEN THIS REGRESSION ANALYSIS AND THE REGRESSION ANALYSIS FROM YOUR TESTIMONY U-21297?

A: Certainly. As stated earlier in my testimony, I reduced the number of independent variables for this iteration.

As seen in both regression models, more densely populated areas experience better SAIDI (fewer minutes of interruption), while more BIPOC communities experience worse SAIDI. This intuitively makes sense because when the Company restores power in a more densely

populated area, it brings more customers on line at the same time, impacting SAIDI. When we look at the 4th regression columns of both analyses, when we look at similarly population-dense communities, BIPOC communities experience longer length interruption.

In my first regression model, communities with higher median income experience more minutes of interruption (worse SAIDI). Similarly, in this new regression model, communities with higher home prices also experience more minutes of service interruption. To me, this is an indication that customers did not see drastic changes to how they experience the reliability of the grid between 2021 and 2023.

However, there is one stark difference between my first regression and this updated regression: the "Constant" value. In terms of regression analysis, the Constant value is the intercept when the independent variables are zero. For the purposes of analyzing SAIDI, the Constant value can be simplified as the "base SAIDI" absent other variables. When comparing my first analysis and the current analysis, all the "base SAIDI" in 2023 is worse than the "base SAIDI" in 2021-2022. This difference hints that 2023 all-weather SAIDI, in general, is worse than in the prior two years. This is corroborated by DTE Witness Kryscynski's testimony, showing a higher AW SAIDI score in 2023.[10]

VII. CONCLUSION AND RECOMMENDATIONS

Q: WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS?

A: While the Commission's order in case U-21297 directed DTE to implement a regression analysis for the distribution grid plan case, I find it valuable to provide new and improved

[10] Direct Testimony of Allen J. Kryscynski on behalf of DTE *In the matter of the application of DTE Electric Company for approval to increase its rates, and for other relief,* Michigan Public Service Commission Docket No. U-21534, March 28, 2024, at 19.

iterations of my regression analysis in this rate case (and future rate cases). My regression analysis does show varying degrees of experiences that customers experience, both positive and negative experiences. Even though I used demographic data as proxy for grid characteristics, my regression analysis demonstrates that it can be improved further with grid topology data. I demonstrated that while setting up the first regression model takes the most effort, updates and subsequent iterations are straightforward. By updating regression with better independent variables, the model can be used to track the progress that DTE is making over time. Once the Company establishes its own regression framework, it must begin to integrate the analyses and findings from regression into its decision-making process, as well as update and improve the regression model with subsequent data and findings. The CEO look forward to participating in this process.

I recommend that DTE provide grid topology data as soon as possible. I also recommend that the Commission also approve the use of regression analysis in rate cases and the distribution grid plans, to be updated upon for each new case.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

MR. ABRAMS: Thank you, your Honor, and thank you for accommodating my schedule. On behalf of the Clean Energy Organizations, we rest our case.

JUDGE WALLACE: Thank you. Mr. Abrams.

O.K. Next, Mr. Vijaykar.

MR. VIJAYKAR: Thank you, your Honor, and echo Mr. Abrams' thanks for accommodating schedules here.

On behalf of EVgo Services, LLC, I move to -- for the admission into the record of the following testimony: Starting with the Direct Testimony of Witness Lindsey R. Stegall, filed on July 26, 2024, consisting of a cover page, a table of contents, and 19 pages of questions and answers, followed by a two-page appendix. I also move for admission into the record of Ms. Lindsey R. Stegall's rebuttal testimony, filed on August 16, 2024, consisting of a cover page, table of contents, and a 14-page set of questions and answers. And finally, I move for admission into the record of Exhibits EVG-1 through EVG-3.

JUDGE WALLACE: O.K. Is there any objection to binding in the direct and rebuttal testimony of Ms. Stegall?

Hearing none, the testimony is bound in.

Is there any objection to the admission of Exhibits EVG-1 through EVG-3?

Hearing none, those exhibits are admitted.

(Testimony bound in.)

- - -

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 ALJ Sally Wallace

DIRECT TESTIMONY OF LINDSEY R. STEGALL

ON BEHALF OF EVGO SERVICES, LLC

JULY 26, 2024

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I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q: Please state your name, title and business address.

A: My name is Lindsey R. Stegall, and I am a Senior Manager of Market Development and Public Policy at EVgo Services, LLC ("EVgo"). EVgo's business address is 11835 W. Olympic Blvd. Suite 900E Los Angeles, CA 90064.

Q: Have you prepared a statement of your experience and qualifications?

A: Yes. My qualifications are included as Appendix A to this testimony.

Q: On whose behalf are you testifying in this proceeding?

A: I am testifying on behalf of EVgo. EVgo is a leader in electric vehicle ("EV") charging solutions, building and operating the infrastructure and tools needed to expedite the mass adoption of EVs for individual drivers, rideshare and commercial fleets, and businesses. EVgo is one of the nation's largest public fast charging providers, featuring over 1,000 fast charging locations across more than 35 states, including stations built through EVgo eXtend™, its white label service offering. EVgo is accelerating transportation electrification ("TE") through partnerships with automakers, fleet and rideshare operators, retail hosts such as grocery stores, shopping centers, and gas stations, policy leaders, and other organizations.

Under its owner-operator business model, EVgo develops, finances, owns, and operates its fast-charging network. EVgo works with site host partners across the country to deploy EV charging solutions at retail locations that are already part of customers' daily routines. EVgo installs the public direct current fast chargers ("DCFC") at no cost to the site host partner. EVgo also maintains the customer relationship with the EV driver, providing a call center that is available to customers 24/7, and is responsible for operations and maintenance of its EV charging network. As of the end of the first quarter of 2024,

nearly 40% of EVgo's fast charging stalls were powered by a 350kW charger—almost double the percentage a year ago—to best serve vehicle models with the most advanced battery technology and high peak charging speeds.

Q: What is EVgo's interest in this proceeding?

A: EVgo is an active participant in the competitive market for DCFC in Michigan. EVgo currently owns and operates more than 40 fast-charging stalls in the state—all of which are in DTE Electric Company's ("DTE" or "the Company") service territory—and has plans for future expansion. EVgo takes into account several factors when identifying markets in which to develop DCFC, including state policies and regulations, utility make-ready and incentive programs, the competitive landscape, tariff designs, state and federal funding programs, and a number of other factors. The outcome of this proceeding will have a substantial impact on the nature, growth, and economics of the competitive market for DCFC in Michigan because DTE has proposed a suite of transportation electrification programs including a modified version of its existing "Business Charger Rebates" program. As a DTE customer, EVgo is also impacted by the rates DTE proposes or describes in its rate case application—including in particular a novel rate targeted at DCFC ("EV Fast Charger rate"). EVgo therefore has a substantial and direct interest in the outcome of this proceeding.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to provide the Commission and DTE with recommendations that will help ensure DTE's transportation electrification programs maximize ratepayer benefits while accelerating the equitable deployment of EV charging

infrastructure in DTE's service territory. In particular, I will discuss DTE's Business Charger Rebates program and the EV Fast Charger rate DTE put forward for discussion.

Q: At a high level, what is your reaction to DTE's modified Business Charger Rebates program?

A: DTE's existing Business Charger Rebates program has been one of the most successful components of DTE's broader "Charging Forward" EV program. EVgo participates in the Business Charger Rebates program and has supported the steady growth of that program in DTE's recent rate cases.

In this case, DTE proposes a major modification to the Business Charger Rebates program: DTE proposes to limit the availability of incentives to chargers located near major throughways (also known as "corridor" locations) going forward and will no longer provide incentives to chargers in "destination" locations (also known as "community" locations) that are more than 1 mile from a major throughway. I am concerned this significant new limitation could result in the inequitable distribution of chargers in DTE's service territory, especially for multifamily housing residents and others who rely on public charging. I am also concerned it could limit program participation.

Q: At a high level, what is your reaction to the EV Fast Charger rate DTE described in its testimony?

A: As DTE itself acknowledges, the EV Fast Charger rate described in DTE's testimony was developed based on exceedingly limited data (21 customers). Implementing a rate based on the load data of 21 customers could have adverse effects on both individual customers and the industry more broadly. I agree with the Company's assessment that the rate should not be implemented at the conclusion of this case.

Q: Please summarize your recommendations to the Commission in this proceeding.

A: I recommend the Commission:

- Direct the Company to support both corridor *and* community locations through the Business Charger Rebates program (similar to the scope of the existing program) and eliminate the requirement that participating sites be located "on-route" in both the DAC/rural and the non-DAC/rural subsegments of the program;
- Direct the Company to reallocate any funds remaining from the existing Business Charger Rebate program on December 31, 2024 into the non-DAC/rural subsegment of the proposed Business Charger Rebate program instead of allowing the utility to determine the reallocation of these funds at a later date; and
- Adopt DTE's proposal to take no further action related to the EV Fast Charger rate at this time.

Q: Do you sponsor any exhibits to your testimony?

A: Yes. I sponsor the following exhibits to my testimony:

- Exhibit EVG-1 (LRS-1): Compiled discovery responses.
- Exhibit EVG-2 (LRS-2): EVgo and ChargePoint comments on DTE's draft TEP.

II. BACKGROUND ON EV CHARGING INFRASTRUCTURE INCENTIVE PROGRAMS

Q: What is the purpose of this section of your testimony?

A: In this section of my testimony, I provide background on the role that utility EV DCFC infrastructure incentive programs can play in accelerating EV adoption and delivering benefits to ratepayers and society.

Q: What is DCFC infrastructure?

A: Public or commercial DCFC charges a vehicle's battery using direct current at high power, which allows for fast charging in minutes instead of hours. DCFC is well-suited for quick charge needs in and around cities, towns, and suburbs and along high-traffic travel corridors. DCFC stations are located at or near places where drivers live, drive, and shop, including retail locations, restaurants, grocery stores, and other locations where an EV driver will be for 15-45 minutes. By contrast, Level 2 charging typically provides a full charge in 4 to 8 hours and is sought in longer duration, long dwell-time locations such as at workplaces, homes, amusement parks, or other destinations where drivers may spend several hours.

Q: How does DCFC infrastructure drive EV adoption, especially for those without access to home charging?

A: Public DCFC helps drive EV adoption—and therefore increases charging and electric load—by serving a variety of drivers' needs. DCFC builds the range confidence of EV drivers, especially on trips between cities or across the country. DCFC locations serving this need are commonly known as "corridor" locations. Public DCFC plays an equally important role in dense, urban, and suburban areas where not every home has a driveway, attached garage, or in many cases, any dedicated parking. DCFC locations serving this need are commonly known as "community" locations. According to the International Council on Clean Transportation, apartment-dwelling EV drivers living in multifamily housing rely on public charging for 50-80% of their charging[1] as they typically do not have

[1] International Council on Clean Transportation, *Quantifying the Electric Vehicle Charging Infrastructure Gap Across U.S. Markets* at 9 (Jan. 2019), available at https://theicct.org/sites/default/files/publications/US_charging_Gap_20190124.pdf.

access to dedicated parking or home charging. Thus, siting DCFC in community locations near multifamily housing and existing amenities drives EV adoption by providing charging options to drivers that do not own a single-family home. For this reason, deploying public DCFC in more dense metropolitan areas is key to enabling equity goals.

Q: How do well-designed EV DCFC infrastructure incentive programs benefit utility ratepayers?

A: Programs that defray the costs of deploying DCFC infrastructure foster private investment and drive the deployment of EV charging stations, which facilitate broader EV adoption and increased charging. Increased EV charging increases the utility's electric load and thereby spreads system costs over a greater volume of customers, causing downward pressure on future rates.

These ratepayer benefits are not just theoretical. A 2024 study by Synapse Economics ("Synapse") found that across all regions in the United States, EVs have increased utility revenues more than they have increased utility costs, leading to downward pressure on electric rates for EV-owners and non-EV owners alike. Between 2011 and 2021, Synapse estimates that EV drivers across the country have contributed $3.12 billion more in revenues than associated costs, driving rates down for all customers.[2] The Synapse report shows a positive cumulative net rate impact (revenues greater than costs) from electric vehicles in Michigan between 2011-2021.[3]

[2] Sarah Shenstone-Harris, Paul Rhodes, Jason Frost, Ellen Carlson, Eric Borden, Courtney Lane, Melissa Whited. *Electric Vehicles Are Driving Rates Down for All Customers* at 3 (Jan. 2024).
[3] *Id*. at 5.

Q: What are the other public interest benefits of well-designed EV charging infrastructure incentive programs?

A: As the State of Michigan has recognized in its MI Healthy Climate Plan,[4] programs that effectively support accelerated TE can generate benefits for multiple stakeholders. EV drivers can benefit from reduced vehicle operating costs for EVs as compared to traditional vehicles. The state as a whole can benefit from reduced greenhouse gas emissions, improved air quality and associated health benefits, economic development, and job creation. The economic benefits of TE for ratepayers are widely recognized by utilities and public service commissions across the country.

III. BUSINESS CHARGER REBATES

Q: Please describe DTE's existing Business Charger Rebates program.

A: The Business Charger Rebates program is a core[5] and highly popular component of Charging Forward. Through the program, DTE issues rebates to business and commercial customers. Those rebates defray the costs of installing charging infrastructure. DTE provides rebates of up to $55,000 per DCFC and $2,000 per Level 2 port with no limitations with regard to the geography of participating sites.

Q: Has the Business Charger Rebates program been successful in deploying EV chargers in DTE's service territory?

A: Yes. The Business Charger Rebates program has been a critical factor contributing to the growth of EV charging station deployment in DTE's service territory. Historically, the program has been so popular that its funding has quickly been exhausted, and applicants

[4] Michigan Department of Environment, Great Lakes and Energy, MI Healthy Climate Plan, April 2022, available at: https://www.michigan.gov/egle/about/organization/climate-and-energy/mi-healthy-climate-plan.
[5] Case No. U-21297, Direct Testimony of DTE witness Peterson at KP-41, lines 23-25.

have been waitlisted.[6] According to DTE, the program has led to the installation of 310 sites with over 1,400 ports operational as of May 17, 2024. This is very near the Company's previous target of 1,500 ports.[7] The Company also has 149 sites (593 ports) in the pipeline to receive funding through DTE Electric's Business Charger Rebates program. DTE agrees the program has been successful.[8]

Q: Please summarize DTE's proposal in this proceeding with respect to the Business Charger Rebates program.

A: In this proceeding, the Company proposes to impose geographic limitations on projects that may receive support from the Business Charger Rebates Program. In order to participate, sites must be in "on-route" locations. DTE defines "on route" as fast charging within one mile of a major throughway exit,[9] with major throughway referring to "a high-traffic road that is likely to be a limited access Interstate or State highway."[10] DTE proposes to offer a rebate of $70,000 per on-route DCFC in disadvantaged communities and rural areas and $50,000 per on-route DCFC in other areas.[11] The Company proposes a budget of $21.6 million in the DAC and rural on-route subsegment and $15.4 million in other on-route areas.[12] Importantly, DTE proposes to eliminate incentives for DCFC "destination charging," also known as community charging, despite the need to serve drivers who cannot charge at home.

[6] Case No. U-20836, Direct Testimony of DTE witness Burns at BJHB-38.
[7] *See* Exhibit EVG-1 (LRS-1), DTE response to EVgoDE-1.4.
[8] *See id*.
[9] DTE testimony part 1 at PB-46:4-5.
[10] *See* Exhibit EVG-1 (LRS-1), DTE response to EVgoDE-1.5.
[11] DTE testimony part 1 at PB-46:6-9.
[12] *Id*. at PB-46:11-12.

Q: Do you have any concerns with regard to DTE's proposal to eliminate incentives for community DCFC?

A: Yes. While I commend the Company for proposing to continue supporting the deployment of fast charging in its service territory, and while I support DTE's proposal to allocate a portion of the available funding to DACs and rural areas, DTE's proposal to limit eligibility to "on-route" locations concerns me. While "on-route," locations are an important use case, limiting program support to these locations while excluding community locations could lead to unintended and adverse consequences. Specifically, this approach could result in inequitable outcomes by limiting charging opportunities for those without access to home charging and those in areas without a major corridor. This approach may also limit program participation. Further, the Company has not justified its proposal to narrow program eligibility. I will explain each of these concerns in detail below.

Q: Please explain how DTE's proposal to eliminate incentives for community DCFC could lead to inequitable outcomes related to access to public fast chargers in DTE's service territory.

A: If the private market is incented to deploy chargers only along major corridors (*i.e.*, on-route locations), the number of community charging sites may not keep pace with demand, leading to gaps in some urban and suburban areas. This would be concerning for multiple reasons. First, it would lead to fewer conveniently located chargers along EV drivers' daily routes in community locations that may be more than one mile away from a corridor. Second, multifamily housing residents and renters rely on public DCFC in community locations to charge their vehicles, as this group of EV drivers typically does not have access to home charging. Prioritizing corridor charging over community charging may therefore

slow EV adoption among drivers that do not own single-family homes, all else equal. Again, I support DTE's proposal to carve out funding for charging locations in DACs and rural areas, but by restricting that funding to "on-route" locations, DTE's proposal may inadvertently reduce the number of DAC residents served by the program and may fail to achieve the program's goal of breaking down barriers for low- and moderate-income customers and disadvantaged communities.[13]

Q: Please explain how DTE's proposal to eliminate incentives for community DCFC could reduce participation in the Business Charger Rebates program.

A: DTE is proposing a $37 million budget for this program over the TEP timeframe from 2025 to 2028—an increase in annual budget compared to previous years. However, with additional program restrictions, it may be difficult to achieve the level of program participation DTE is expecting. There are many factors that must be considered in siting a charging station, such as traffic patterns, EV density, proximity of other DCFC, environmental justice considerations, multifamily housing proximity, amenities, and existing relationships with potential site hosts. Additional geographic requirements will further limit the pool of potential sites and may create a barrier to program participation.

Q: Does the Company justify its proposal to eliminate incentives for community DCFC?

A: Not adequately. In its direct testimony, DTE notes that "[r]eliable, 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." The Company also states that it "does not, however, propose rebates for the destination charging segments as the economics of Level 2 charger deployment are not as challenging, and businesses have other

[13] *Id*. at PB-14:24-25

motivation for installation such as increased foot traffic. For site hosts installing a destination DCFC, DTE Electric will continue to offer a commercially available rate without demand charges for sites less than one megawatt."[14]

Further, in discovery, DTE states "[d]estination chargers, by definition, are located at businesses like hotels, restaurants, or grocery stores, that may not be located within one mile of a major throughway. In order to balance public charger support with overall customer affordability the Company considered that these businesses have other incentives and motivations for charger installation, like increasing foot traffic and attracting customers to their businesses. Therefore, the Company determined to direct finite incentives to locations with fewer such incentives and inherent benefits."[15]

Q: What are your concerns with this explanation?

A: First, while the Company provides a reason for excluding Level 2 community charging locations from the program, it does not explain why it proposes to eliminate incentives for community DCFC locations. In discovery, DTE expands on this topic, suggesting that certain types of businesses located more than a mile from a major throughway may have other incentives and motivations for charger installation.[16] However, these same types of businesses—grocery stores, restaurants, and other retailers—can also be located *within* one mile of a major throughway. It is unclear why the incentives for installing chargers would differ for businesses based solely on their distance from a major throughway.

[14] *Id*. at PB-47:1-6.
[15] *See* Exhibit EVG-1 (LRS-1), DTE Response to EVgoDE-1.12.
[16] *See id*.

Q: Is DTE's proposal justified by stakeholder feedback the Company received prior to its rate case filing?

A: No. In fact, excluding destination charging from the program is contrary to the feedback DTE received from stakeholders. As DTE notes, "[s]takeholders 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."[17] (Emphasis added). When asked to provide any feedback the Company received that supports the exclusion of rebates for community DCFC in its TEP, DTE provided no direct feedback from stakeholders.[18]

Q: Did EVgo provide feedback to DTE regarding the Business Charger Rebates program through the stakeholder process preceding this rate case filing?

A: Yes. DTE's initial proposal was to limit the Business Charger Rebate program to DAC and rural on-route deployments. Prior to this rate case filing, EVgo and ChargePoint provided joint feedback to DTE[19] supporting the Business Charger Rebate program in its current form and recommending DTE extend the availability of this program, without geographic limitations, in the TEP. We expressed our concern that DTE's proposal to narrow the availability of Business Charger rebates to DACs and rural on-route deployments in its TEP could stall the market's momentum and adversely impact market stability in DTE's territory. We also explained that the National Electric Vehicle Infrastructure ("NEVI") Formula program will support sites near corridors—areas similar to DTE's "on-route" areas—and therefore recommended DTE support the deployment of chargers in areas that

[17] DTE testimony part 1 at PB-46:1-4
[18] *See* Exhibit EVG-1 (LRS-1), DTE response to EVgoDE-1.12.
[19] *See* Exhibit EVG-2 (LRS-2).

do not qualify for NEVI funding in order to encourage the broad geographic distribution of charging infrastructure.[20] Finally, we recommended options that would allow DTE to address DAC/rural charging gaps while also supporting the broader market.

Q: How did DTE respond to EVgo and ChargePoint's recommendation?

A: The Company explained that it expanded its Business Charger Rebate program to on-route DCFCs outside of DAC or rural areas in response to feedback it received.[21]

Q: Did this resolve the concerns EVgo raised?

A: While expanding eligibility to "on route" locations outside of DACs and rural areas was a step in the right direction, DTE's modification did not alleviate EVgo's concerns because the Business Charger Rebates program (as-filed) continues to limit eligibility to on-route locations, which, as noted above, does not enable equitable charging access for those living in multifamily housing and others without access to home charging.

Q: What do you recommend to the Commission with respect to the Business Charger Rebates program?

A: I recommend the Commission direct the Company to support both corridor and community locations through the Business Charger Rebate program (similar to scope of the existing program) and eliminate the requirement that participating sites be located "on-route" in both the DAC/rural and the non-DAC/rural subsegments of the program.

[20] The Michigan Department of Transportation has since announced 41 NEVI project selections amounting to $22.9 million in requested funds.
[21] DTE testimony part 1 at PB-46:22-25.

Q: Is there a way for the Company to encourage the deployment of corridor charging without eliminating incentives for community charging?

A: Yes. If the Company wishes to encourage participants to develop "on-route" sites, it should incorporate this preference into its scoring rubric instead of eliminating support for DCFC community charging altogether.

Q: Please elaborate.

A: In its last rate case, the Commission ordered DTE to work with stakeholders to develop a points-based scoring rubric to transparently evaluate applicants to the Business Charger Rebates program.[22] To the extent DTE has a reasonable preference for certain types of deployments (*i.e.*, corridor locations) they can reflect that preference by assigning additional points to specific types of deployments in the scoring rubric. This would have the practical effect of encouraging DTE's "preferred" deployments without eliminating support for other deployments; ultimately allowing private market participants to continue to optimize siting for the benefit of EV drivers.

Q: What are the benefits of supporting both corridor and community locations through the Business Charger Rebates program?

A: This geographically inclusive approach is in line with the existing, successful Business Charger Rebates program, which does not include an "on-route" requirement. Allowing sites in both DAC/rural and non DAC/rural areas to be located either on corridors or in communities will result in a more equitable distribution of charging infrastructure across DTE's service territory. Critically, making Business Charger Rebates available for corridor and community charging will help make EVs accessible to multifamily housing residents,

[22] Case No. U-21297, Final Decision at 373-374.

renters and others without access to home charging. Providing this flexibility will also increase the number of communities that can be served by the program, particularly in disadvantaged and rural areas, and ensure that chargers are conveniently located, even if a resident lives farther from a major throughway.

Additionally, making Business Charger Rebates available for both corridor and community charging will allow DTE to leverage the expertise of the private market in siting chargers to ensure they are located in the most convenient locations where the greatest need exists. EV charging providers like EVgo have a significant amount of experience siting fast charging locations and have the ability to utilize tools that incorporate years of data and several critical factors into charger siting. This allows us to understand which locations have the greatest need and predict the extent to which each location will be utilized by drivers. Thus, removing the restrictive on-route requirement will increase the pool of potential sites and applicants and will ensure robust program participation. Ultimately, a successful program that effectively drives charging infrastructure deployment will maximize DTE ratepayer benefits and other public interest benefits, while helping the State of Michigan meet the ambitious transportation electrification goals in its MI Healthy Climate Plan.[23]

Q: Do you have any other recommendations with regard to the Business Charger Rebates program?

A: Yes, I have one recommendation with regard to the existing Business Charger Rebates program. In discovery, the Company noted that there was approximately $5 million in

[23] Michigan Department of Environment, Great Lakes and Energy, MI Healthy Climate Plan, April 2022, available at: https://www.michigan.gov/egle/about/organization/climate-and-energy/mi-healthy-climate-plan.

funding remaining in Business Charger Rebate program as of May 17, 2024.[24] DTE explained this funding will only be available to applicants for sites operationalized by December 31, 2024[25] and "[i]f funding for the Business Charger Rebate program is not depleted by the time the Company's proposed Transportation Electrification Program (TEP) is implemented, the Company plans to consult with stakeholders regarding potential reallocation of the remaining funds approved for the Business Charger Rebates program to other programs such as the TEP's Public charging for Other On-route DCFC segment."[26] While DTE suggests that funding *may* be reallocated to the non-DAC/rural subsegment of the Business Charger Rebates program proposed in this proceeding, this outcome is not certain.

Therefore, I recommend the Commission direct the Company to reallocate any funds remaining from the existing Business Charger Rebate program into the non-DAC/rural subsegment of the proposed Business Charger Rebate program instead of allowing the utility to determine the reallocation of these funds at a later date. This will provide greater funding certainty for the charging industry, which is crucial for creating a stable market environment that supports continuous deployment, rather than a "start and stop" cycle of development.

IV. EV FAST CHARGER RATE

Q: Please summarize DTE's EV Fast Charger rate design.

A: As directed by the Commission in its last rate case,[27] DTE describes an EV Fast Charger rate design in its testimony. DTE presents this rate as "a starting point for discussion only

[24] *See* Exhibit EVG-1 (LRS-1), DTE Response to EVgoDE-1.1d.
[25] *See* Exhibit EVG-1 (LRS-1), DTE Response to EVgoDE-1.2.
[26] *See* Exhibit EVG-1 (LRS-1), DTE Response to EVgoDE-1.3.
[27] Case No. U-21297, Final Decision at 342.

and not as a rate to be implemented at the conclusion of this case."[28] DTE explains that determinants and load shape for the EV Fast Charger rate were based on usage from a small set of current, known EV fast chargers on separate meters with more than 300 read days—a total of 21 chargers.[29]

Q: What concerns did the Company raise regarding the EV Fast Charger rate?

A: The Company expressed concerns about the data sample size and quality. The Company notes that "[t]he sample size is small because the overall density of EV fast chargers is still small relative to customer counts in other cost of service classes. Very small cost of service classes such as this one can lead to volatile determinants, COS, and rate design from case to case and individual customers may have an outsized impact on the overall class."[30] DTE also points out "[t]he sample size, while reasonably defined, does not include all EV fast chargers served by the Company given the co-location of charging load with other general service loads."[31] In conclusion, the Company states "[t]he 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."[32]

Q: What do you recommend with regard to the EV Fast Charger rate?

A: I share DTE's concerns regarding the size and quality of the data used to design the EV Fast Charger rate. 21 customers is an exceedingly small sample size—susceptible to outsize effects from the characteristics of a single customer's usage. Designing a rate based on such a small set of customers could have adverse effects both on individual customers and

[28] DTE testimony part 2 at AW-36:14-17.
[29] *Id*. at AW-35:11-24.
[30] *Id*. at AW-36:3-7.
[31] *Id*. at AW-36:8-10.
[32] *Id*. at AW-36:14-17.

the industry more broadly. I therefore agree with the Company's assessment that the EV Fast Charger rate should not be implemented at the conclusion of this case. I recommend the Commission approve DTE's proposal to take no further action related to the EV Fast Charger rate at this time.

Q: Have utilities and Commissions in other states had similar experiences related to creating a separate rate class for EV charging customers?

A: Yes. While many Commissions across the country have approved EV fast charging rates, in EVgo's experience, EV charging customers are rarely, if ever, placed in a separate rate class. To date, Commissions and utilities have generally rejected proposals for developing a separate rate class for EV charging customers for reasons similar to those presented by DTE in this case. In Illinois, for example, the Commission rejected Commonwealth Edison Company's proposal to create separate EV charging delivery classes, expressing concerns regarding the lack of data on the proposed new delivery classes, and finding that the proposal was premature.[33] Similarly, through a settlement agreement in a 2021 proceeding in Colorado, Public Utilities Commission Staff and the utility, Public Service Company of Colorado, agreed to avoid a standalone rate class for commercial EV charging and a separate cost allocation for the EV rates in the next rate case due to the relatively small number of EV charging customers and total load.[34] Finally, in a recent Jersey Central Power & Light Company ("JCP&L") Base Rate Filing the utility noted "there is limited data to develop a [cost of service study] and design a commercial Direct-current fast

[33] Ill. Commerce Comm'n, Docket Nos. 22-0432 and 22-0442 (cons.), Final Order at 237.
[34] Colorado Public Utilities Commission, 21AL-0494E, Non-Unanimous Comprehensive Settlement Agreement at 4.

charger ("DCFC") rate..." showing that there was only 8 months of DCFC data and only 7 out of 13 chargers with data available during June and July—the system peak.[35]

V. CONCLUSION

Q: Please summarize your recommendations to the Commission.

A: I recommend that the Commission:

a. Direct the Company to support both corridor *and* community locations through the Business Charger Rebates program (similar to the scope of the existing program), and eliminate the requirement that participating sites be located "on-route" in both the DAC/rural and the non-DAC/rural subsegments of the program.

b. Direct the Company to reallocate any funds remaining from the existing Business Charger Rebate program on December 31, 2024 into the non-DAC/rural subsegment of the proposed Business Charger Rebate program instead of allowing the utility to determine the reallocation of these funds at a later date.

c. Adopt DTE's proposal to take no further action related to the EV Fast Charger rate at this time.

Q: Does this conclude your direct testimony?

A: Yes.

[35] JCP&L (Docket No. ER23030144), p. 29:20-30:5, available at: https://www.firstenergycorp.com/content/dam/customer/OpCoHome/files/JCPLRegulatory/JCPL-2023-Base-Rate-Case-Incl-REV-Exh-10.pdf.

Appendix A

Experience & Qualifications: Lindsey R. Stegall

Ms. Stegall serves as Senior Manager of Market Development and Public Policy at EVgo, where she leads the company's policy and regulatory engagement across the Central and Eastern U.S. In this role, Ms. Stegall works with public utilities commissions, state legislatures, state agencies, and other stakeholders to develop and support policies and programs that help accelerate transportation electrification.

Within the last three years, Ms. Stegall served as an expert witness in a PECO rate case in Pennsylvania (Docket No. R-2024-3046931, et al.), a Duke Energy rate case in Florida (Docket No. 20240025-EI), two Massachusetts proceedings related to the Electric Sector Modernization Plans of Eversource Energy (D.P.U. 24-10) and National Grid (D.P.U. 24-11); a DTE rate case proceeding in Michigan (Case No. U-21297); a Colorado Proceeding related to Public Service Company of Colorado's (PSCo) Transportation Electrification Plan (Proceeding No. 23A-0242E); an Arizona Public Service (APS) rate case proceeding (Docket No. E-01345A-22-0144); a Nevada proceeding related to NV Energy's Transportation Electrification Plan (Docket No. 21-09006); and a Colorado proceeding related to PSCo's commercial rates for EV charging (Proceeding No. 21AL-0494E). She also managed EVgo's regulatory engagement in an Oncor Electric rate case in Texas (Docket No. 53601), and transportation electrification plan cases filed by Northern States Power in Minnesota (Docket No. E002/M-22-432), APS in Arizona (Docket No. E01345A-22-0067), NV Energy in Nevada (Docket No. 21-09004), and Rocky Mountain Power in Utah (Docket No. 20-035-34).

Ms. Stegall has more than twelve years of experience in the clean energy sector and has been working on transportation electrification policy since 2018. Prior to joining EVgo in 2021,

Ms. Stegall served as Manager of Policy and Regulatory Affairs at the Colorado Energy Office (CEO), where she was employed for six years. During that time, Ms. Stegall managed CEO's engagement in energy regulatory proceedings before the Colorado Public Utilities Commission, including several related to transportation electrification and rate design.

Ms. Stegall holds a Master of Business Administration degree in Sustainable Management from Presidio Graduate School and a Bachelor of Arts degree from the University of Colorado.

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 ALJ Sally Wallace

REBUTTAL TESTIMONY OF LINDSEY R. STEGALL

ON BEHALF OF EVGO SERVICES, LLC

AUGUST 16, 2024

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I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q: Please state your name, title and business address.

A: My name is Lindsey R. Stegall. I am a Senior Manager of Market Development and Public Policy at EVgo Services, LLC (EVgo). EVgo's business address is 11835 W. Olympic Blvd. Suite 900E Los Angeles, CA 90064.

Q: Are you the same Lindsey R. Stegall that submitted direct testimony on EVgo's behalf in this proceeding?

A: Yes.

Q: What is the purpose of your rebuttal testimony?

A: The purpose of my rebuttal testimony is to respond to the direct testimony of:

- Michigan Public Service Commission Staff (Staff) witness Freeman and Attorney General (AG) witness Coppola, each of whom address DTE Electric Company's (DTE or the Company) proposed electric vehicle (EV) program (known as "Charging Forward") budget;
- Citizens Utility Board of Michigan, Sierra Club, Michigan Environmental Council and Natural Resources Defense Council (MNSC) witness Jester, who recommends DTE prioritize applicants to its "Business Charger Rebate" program that have received funding through Michigan's National Electric Vehicle Infrastructure (NEVI) program, and;
- Walmart, Inc. witness Perry, who recommends the Commission either remove the two-year limitation from Rate Schedule D3 or direct DTE to propose a public EV charging-specific rate informed by data from the alternative Cost of Service Study (COSS) presented in this case, as well as future data, in its next rate case.

Q: Please summarize your recommendations to the Commission.

A: The recommendations I made in direct testimony remain unchanged. I continue to recommend the Commission:

- Direct DTE to support both corridor *and* community charging locations through the Business Charger Rebate program (similar to the scope of the existing program) and eliminate the requirement that participating sites be located "on route" in both the disadvantaged community (DAC)/rural and the non-DAC/rural subsegments of the program;
- Direct the Company to reallocate any funds remaining from the existing Business Charger Rebate program on December 31, 2024 into the non-DAC/rural subsegment of the proposed Business Charger Rebate program instead of allowing the utility to determine the reallocation of these funds at a later date; and
- Adopt DTE's proposal to take no further action related to the EV Fast Charger rate at this time.

Having reviewed the direct testimony submitted by Staff and other intervenors, I further recommend the Commission:

- Decline to adopt either Staff witness Freeman's or AG witness Coppola's recommendations related to DTE's Charging Forward budget, and approve DTE's funding request in its entirety;
- Decline to adopt MNSC witness Jester's recommendation that DTE prioritize Business Charger Rebate applicants receiving NEVI funding;

- Adopt Walmart witness Perry's recommendation to remove the two-year limit on the exemption from the 1,000 kW demand restriction for EV charging stations in Rate Schedule D3; and
- Decline to adopt Walmart witness Perry's recommendation that DTE be directed to propose a public EV charging-specific rate informed by data from the alternative COSS presented in this case, as well as future data, in its next rate case proceeding.

II. DTE'S EV PROGRAM BUDGET

Q: What is the purpose of this section of your testimony?

A: In this section of my testimony, I address Staff witness Freeman's and AG witness Coppola's discussion of DTE's proposed EV program portfolio budget. Both witnesses recommend the Commission significantly reduce DTE's EV program budget. Staff witness Freeman recommends an $8,000,000 disallowance to DTE's Business and eFleet Charger Rebate programs and a $1,000,000 disallowance to DTE's Residential Customer Rebate program.[1] AG witness Coppola recommends a 45% reduction to DTE's forecast capital expenditures for its overall Charging Forward program, which would reduce the Company's forecast capital expenditures by $6,979,000 in 2024 and by $2,295,000 in 2025.[2]

[1] Direct Testimony of Alan Freeman on behalf of MPSC Staff at 8:8-12.
[2] Direct Testimony of Sebastian Coppola on behalf of AG Dana Nessel at 55:6-11. AG witness Coppola also recommends DTE reduce its forecast spending on utility make-ready (UMR) expenditures—which refers to spending on upgrading and installing utility equipment and facilities to support charging infrastructure—by $3,734,000 in 2024 and $10,173,000 in 2025. Direct Testimony of Sebastian Coppola on behalf of AG Dana Nessel at 26:11-12.

Q: Why does witness Freeman recommend reducing DTE's proposed spending on EV-related programs?

A: Staff witness Freeman suggests DTE's proposed spending on its Business and eFleet Charger Rebates programs ($16 million in 2025) represents a "significant increase" from past rebate programs and indicates Staff would prefer DTE implement a "scaled down rebate effort."[3]

Q: What is your response?

A: While I appreciate Staff's desire to ensure DTE uses ratepayer dollars responsibly, I respectfully disagree with Mr. Freeman's recommendation because he (1) mischaracterizes the scale of DTE's funding request for its Business and eFleet Charger Rebate programs, (2) does not provide evidence for disallowing funding in the Business Charger Rebates program in particular—a program that is both critical and widely popular, (3) does not base his recommendation on any analysis of DTE's customers' needs, and (4) does not take into account the ratepayer benefits of these programs. I will explain each of these issues in more detail below.

Q: Please explain your concern with Mr. Freeman's discussion of the scale of DTE's funding request.

A: EVgo sent MPSC Staff discovery requests to clarify what Mr. Freeman means where he references a "significant increase from past rebate programs." In response, Mr. Freeman referenced DTE's actual and estimated Charging Forward spend between 2019 and 2023 ($13,985,000), described in the testimony of DTE witness Peterson in DTE's last rate case, Case No. U-21297.[4] Critically, that number does not include the EV program funding

[3] Direct Testimony of Alan Freeman on behalf of MPSC Staff at 8:18-22.
[4] *See* Exhibit EVG-3 (LRS-3) (MPSC Staff response to EVgo discovery request 1.01c).

authorized by the Commission in Case No. U-21297. In that case, the Commission approved a total of $24.4 million for DTE's Business and eFleet Charger Rebate programs, including $5.8 million to exhaust funding from the original Charging Forward pilot through 2023, $6.9 million for eFleets Business Charger Rebates through 2024, and $11.7 million for expanding Business Charger Rebates through 2024.[5] Relative to the most recently authorized funding for its EV programs, DTE's funding request in this case ($24,980,000 in 2025) cannot reasonably be viewed as a "significant increase" over prior funding levels. Rather, DTE's request, if approved, would steadily scale funding for its EV programs.

Q: Please explain your concern with Mr. Freeman's proposal to reduce funding for the Business Charger Rebate program in particular.

A: Based on his responses to discovery requests issued by EVgo, Mr. Freeman appears to be concerned with the scale of DTE's **overall** 2025 EV budget ($24,980,000), and not specifically with the budget dedicated to the Business and eFleet Charger Rebate programs.[6] Yet, Mr. Freeman's proposed solution is for the Commission to disallow funding for Business Charger Rebates[7]—incentives that would address a charging use case ranked by stakeholders as "the most important for utility action."[8] Mr. Freeman's solution does not map to his concern, and he does not explain why the Commission should address his concern by cutting funding for a popular, critical element of DTE's broader EV program.

[5] Direct Testimony of Pina Bennett on behalf of DTE at PB-8:17-21.
[6] *See* Exhibit EVG-3 (LRS-3) (MPSC Staff response to EVgo discovery request 1.01a).
[7] *See* Exhibit EVG-3 (LRS-3) (MPSC Staff response to EVgo discovery request 1.02a, confirming Mr. Freeman believes the Commission should disallow $8,000,000 in funding from both Business Charger Rebates and eFleet rebates).
[8] Direct Testimony of Pina Bennett on behalf of DTE at PB-46:2.

Q: Please explain your concern related to DTE's customers' needs.

A: Mr. Freeman recommends disallowing $8,000,000 from DTE's Business Charger Rebate and eFleet Charger Rebate programs, but does not ground his recommendation in any analysis of DTE's customers' needs. In contrast, DTE's funding request is grounded in its analysis of the forecasted market size for EV registrations in its service territory;[9] an analysis of the charging infrastructure required to support forecasted EV adoption;[10] and stakeholder engagement,[11] each of which are described in detail in DTE witness Bennett's testimony. With respect to Business Charger Rebates for public charging use-cases, DTE notes "[s]takeholders ranked all the public charging subsegments, including on-route and destination charging, as the most important for utility action[.]"[12] DTE's proposal to steadily scale funding for Business Charger rebates is therefore well-supported, appropriately tailored to the needs of its customers, and consistent with the state's goals related to electrifying the transportation sector.

Q: Please explain your concern with Mr. Freeman's oversight related to considering the ratepayer benefits of EV charging infrastructure programs.

A: Mr. Freeman's recommendation does not appear to consider the ratepayer benefits associated with transportation electrification programs, nor does it balance those benefits against program costs. As I explained in direct testimony, programs that expand EV fast-charging infrastructure promote wider EV adoption and increased charging. This leads to increased electric load for which costs are distributed across a greater number of customers, thereby putting downward pressure on future rates. A 2024 Synapse Economics study

[9] *Id*. at PB-23:5-PB-25:4.
[10] *Id*. at PB-25:6-PB-28:18.
[11] *Id*. at PB-31:22-PB-35:13.
[12] *Id*. at PB-46:1-3.

found that EVs have increased utility revenues more than costs nationwide, resulting in lower electric rates for all customers. From 2011 to 2021, EV drivers contributed $3.12 billion more in revenues than associated costs, resulting in benefits for all ratepayers. The economic benefits of TE for ratepayers are widely recognized by utilities and public service commissions across the country and should be considered along with the costs of these programs.[13]

Q: Why does witness Coppola recommend reducing DTE's proposed spending on EV-related programs?

A: Mr. Coppola makes a series of claims about the health of the EV market. In his direct testimony, Mr. Coppola alludes to issues ranging from the level of inventory at dealers' lots, to the satisfaction levels of EV drivers, to equipment reliability, to EV manufacturers' production schedules—without offering any specific support for his broad assertions. Through discovery, Mr. Coppola provided seven news articles on which he relied, including two articles related specifically to the earnings of Tesla and two articles related to the European EV market. None of these articles were specific to the EV market in the state of Michigan or in DTE's service territory. Further, Mr. Coppola does not attempt to connect the various issues he lists to the specific needs of DTEs' customers within each Charging Forward subsegment (*i.e.*, residential, multi-unit dwelling; public charging; fleet charging; etc.), nor does he address DTE witness Bennett's quantitative analysis of those needs. Instead, Mr. Coppola requests the Commission indiscriminately reduce the overall budget for DTE's highly successful Charging Forward program.

[13] Direct Testimony of Lindsey R. Stegall on behalf of EVgo at 6:5-7:9.

Q: How do you respond?

A: Mr. Coppola's testimony is concerning because he provides little evidence to support his broad assertions. Putting aside Mr. Coppola's oversight in not connecting his diagnosis of the EV market with the needs of DTE's customers within each Charging Forward subsegment, Mr. Coppola's diagnosis is both inaccurate and misleading.

Q: Please elaborate.

A: As DTE witness Bennett's testimony explains in detail, EV sales are accelerating—not slowing down, suggesting that consumer demand for EVs remains healthy. At the national level, a record 1.2 million new EVs were sold in 2023.[14] That trend has continued in 2024—a record-high 330,463 EVs were sold in the second quarter of 2024, representing an 11.3% increase relative to the second quarter of 2023.[15] Growth in non-Tesla EV sales has been exceptionally strong, with 35% year-over-year growth in the second quarter of 2024.[16] This growth in non-Tesla EV sales is notable, as these vehicles are those most likely to rely on charging networks like EVgo's for their fueling needs. According to DTE witness Bennett, these trends extend to DTE's service territory—the Company forecasts total EV registration growth in its service territory from 46,000 in 2023 to 65,000 in 2024, and to 326,000 by 2028,[17] the end of the first cycle of its proposed Transportation Electrification Plan (TEP)—a 600% increase compared to 2023.

Increasing sales are driven in part by declining prices and increased availability of affordable vehicle models for consumers. Two years ago, the average EV was

[14] *See* Cox Automotive, "A Record 1.2 Million EVs Were Sold in the U.S. in 2023, According to Estimates from Kelley Blue Book." Jan. 9, 2024. Available at: https://www.coxautoinc.com/market-insights/q4-2023-ev-sales/.
[15] *See* Cox Automotive, "Despite Tesla Slide, EV Sales in Q2 Mark New Record." Jul. 11, 2024. Available at: https://www.coxautoinc.com/market-insights/q2-2024-ev-sales/.
[16] *See* EVgo Investor Relations, EVgo Q2 Investor Presentation. Available at: https://investors.evgo.com/overview/default.aspx.
[17] Direct Testimony of Pina Bennett on behalf of DTE at PB-24:1-2.

approximately 33% more expensive than the average internal combustion engine (ICE) vehicle, whereas at of the end of last year, the price of an average EV was almost at parity with the average ICE vehicle without incentives.[18] Further, industry projections suggest that 38 EV models with price points less than $35,000 will be available within the next 18 months and average EV sales prices will be lower than average ICE vehicles in 2026.[19]

In sum, the evidence is clear that the EV market is growing and programs that provide support for fast charging infrastructure will only serve to further accelerate this growth.

Q: Do you have any other concerns about Mr. Coppola's testimony regarding DTE's Charging Forward budget?

A: Yes. Even if Mr. Coppola's diagnosis of the EV market were accurate, his recommended solution would only exacerbate the issues he describes. DTE's Charging Forward programs are primarily *charging infrastructure* programs, aimed in part at reducing customers' range anxiety[20] and spurring EV adoption. Furthermore, a recent study conducted by Pew Research Center found that "Americans who live close to public chargers view EVs more positively than those who are farther away,"[21] which suggests that increasing exposure to EV charging infrastructure by deploying it in communities is key to driving EV adoption. Slashing the budget for these programs would discourage the deployment of public EV

[18] *See* Cox Automotive, "New-Vehicle Transaction Prices Decline Further in September, Led by Price Cuts at Tesla, According to Kelley Blue Book Report." Oct. 11, 2023. Available at: https://www.coxautoinc.com/market-insights/kbb-atp-september-2023/.
[19] *See* EVgo Investor Relations, EVgo Q2 Investor Presentation. Available at: https://investors.evgo.com/overview/default.aspx.
[20] Direct Testimony of Pina Bennett on behalf of DTE at PB-46:3.
[21] *See* Samuel Bestvater and Sono Shah, Pew Research Center, "Electric Vehicle Charging Infrastructure in the U.S. (May 23, 2024). Available at: https://www.pewresearch.org/data-labs/2024/05/23/electric-vehicle-charging-infrastructure-in-the-u-s/.

charging which would do little to help DTE's customers considering an EV purchase, or DTE's customers who are already EV drivers.

Q: What do you recommend to the Commission with respect to Staff witness Freeman and AG witness Coppola's recommendation regarding DTE's Charging Forward budget?

A: I recommend the Commission decline to adopt Staff witness Freeman's and AG witness Coppola's recommendations.

III. PUBLIC CHARGING PROGRAM PRIORITIZATION CRITERIA

Q: What is the purpose of this section of your testimony?

A: In this section of my testimony, I address MNSC witness Jester's recommendation regarding DTE's evaluation of applicants to its Business Charger Rebate program—a program my direct testimony addresses at length.

Q: Please summarize Mr. Jester's recommendation.

A: Mr. Jester recommends DTE prioritize Business Charger Rebate program applications from prospective participants that are also seeking (or have secured) funding through Michigan's NEVI program.[22]

Q: How do you respond?

A: As I understand Mr. Jester's testimony, his view is that prioritizing participants that are seeking or have secured NEVI funding will help ensure DTE's programs complement federal funding for transportation electrification. While I support the general goal of coordinating federal, state, and utility programs, seeking to maximize "stacking" of

[22] Direct Testimony of Douglas B. Jester on behalf of MNSC at 39:3-5.

funding is not the optimal strategy for coordination and is likely to diminish the effectiveness and cost-efficiency of DTE's Business Charger Rebate program.

Q: Please elaborate

A: As Mr. Jester explains, the NEVI program provides support for up to 80% of project costs.[23] Projects receiving NEVI funding, therefore, are less likely to require *additional* funding from DTE in order to be built—those projects are likely to be built through the NEVI program without incremental support. Prioritizing applicants that have received NEVI funding would increase the number of free riders on DTE's programs—in this case, those who would have developed sites with NEVI funding alone.

Instead of providing additional funding to sites already receiving substantial funding, DTE should aim to support projects that do not qualify for NEVI funding, such as sites in community locations, as these sites may not be developed without utility program support. This approach will serve to fill gaps in the charging network left by the NEVI program and will support the deployment of projects at "community" locations—public chargers in urban and suburban areas away from corridors, where not every home has a driveway, attached garage, or dedicated parking. As I explained in my direct testimony, community fast charging is particularly important for drivers that do not have access to home charging and is key to enabling equity goals.[24] By prioritizing projects that do not qualify for NEVI funding, DTE can not only increase the number of chargers deployed in DTE's service territory but also broaden the geographic distribution of those chargers.

Targeting projects that do not qualify for NEVI funding in the Business Charger Rebate program will also ensure that ratepayer funding is used efficiently—directed toward

[23] *Id*. at 38:5-8.
[24] Direct Testimony of Lindsey R. Stegall on behalf of EVgo at 5:19-6:4.

sites that require support for development, rather than those that would have been built regardless, leveraging funding from the federal government.

Q: What do you recommend to the Commission with respect to Mr. Jester's recommendation?

A: I recommend the Commission decline to adopt Mr. Jester's recommendation.

IV. RATE DESIGN FOR EV FAST CHARGING

Q: What is the purpose of this section of your testimony?

A: In this section of my testimony, I respond to Walmart witness Perry's discussion of DTE's Rate Schedule D3 and DTE's alternative COSS and EV Fast Charger rate.

Q: Please explain Rate Schedule D3 as it applies to EV fast-charging customers.

A: Rate Schedule D3—which does not include demand charges—is typically available to commercial customers with a demand lower than 1,000 kW, including EV fast-charging customers that fall below that limit. The rate also includes an exemption from the 1,000-kW demand restriction for EV charging stations until January 1, 2026, enabling EV charging stations with greater demand to access the rate until that time.

Q: Please summarize Ms. Perry's testimony regarding Schedule D3 and the rate design for EV fast charging.

A: Ms. Perry, along with MEIU witness Dr. Sherman and other intervenors,[25] expresses concern over the limited availability of Rate Schedule D3 to separately metered DC fast chargers, and explains that a more durable rate for EV fast chargers would foster market certainty and encourage investments in public EV charging.[26] Ms. Perry does not support the approval of an EV fast charging-specific rate based on the alternative COSS DTE

[25] *See, e.g.* Direct Testimony of Jigar Shah on behalf of Electrify America at 2-5.
[26] Direct Testimony of Lisa V. Perry on behalf of Walmart, Inc. at 24:7-10.

presented in this rate case because the data used in that study is limited.[27] To address the lack of viable and durable rate options for EV fast chargers, Ms. Perry recommends the Commission direct DTE to "either remove the two-year limitation from Rate Schedule D3 or require the Company to collaborate with interested parties to develop a public EV charging-specific rate that is informed by data from the alternative COSS presented in this case as well as future data, and require the Company to seek approval of such rate in its next general rate case."[28]

Q: How do you respond to Ms. Perry's recommendation?

A: I share Ms. Perry's concern and I support the first option she recommends, which I interpret to mean removing the two-year limit on the exemption from the 1,000 kW demand restriction for EV charging stations in Rate Schedule D3. This will create a more inclusive rate that will promote market certainty over the long term and foster private investment in EV charging, particularly as charger power levels trend upward to accommodate increasing vehicle charging speeds.

However, I recommend the Commission decline to adopt the second option recommended by Ms. Perry—requiring the Company to seek approval of an EV charging-specific rate that is informed by data from the alternative COSS presented in this case as well as future data *in its next general rate case.* Considering the issues with the data sample size and quality related to the EV Fast Charger Rate, which DTE has acknowledged, and given that DTE typically files rate cases on an annual basis, similar data challenges are likely to exist in next year's rate case.

[27] *Id*. at 24:3-6.
[28] *Id*. at 24:14-17.

Q: Do you have any further recommendations related to this topic?

A: Yes. If the Commission declines to remove the two-year exemption limit in Rate Schedule D3, I recommend the Commission direct DTE to collaborate with stakeholders to develop an optional successor rate to Schedule D3 for EV fast-charging customers which should be available upon the expiration of the Schedule D3 exemption from the demand restriction for EV charging stations. Developing this optional EV fast-charging rate should not necessitate creating a separate EV fast-charging rate class. As I explained in my direct testimony, many Commissions across the country have approved EV fast charging rates, though EV charging customers are rarely, if ever, placed in a separate rate class.[29] EVgo would be happy to collaborate with DTE and share best practices from across the country through the stakeholder process I recommend.

V. CONCLUSION

Q: Does this conclude your rebuttal testimony?

A: Yes.

[29] Direct Testimony of Lindsey R. Stegall on behalf of EVgo at 18:5-19:2.

MR. VIJAYKAR: That's all we have, your Honor. Thank you very much.

JUDGE WALLACE: Thank you. All right. And then Kroger wants to go last or later. So Mr. Campbell, are you here?

MR. CAMPBELL: Yes, your Honor. Thank you. At this time --

JUDGE WALLACE: Please go ahead.

MR. CAMPBELL: At this time, on behalf of the Association of Businesses Advocating Tariff Equity, I'd move to bind into the record the Direct and Rebuttal Testimony of ABATE Witnesses Jessica York, James Dauphinais, Chris Walters, and Brian Andrews, and for the admission of their associated exhibits.

Ms. York's direct testimony consists of a cover page, a table of contents, 32 pages of questions and answers, and an appendix A setting out her qualifications; and along with her direct testimony, Ms. York sponsored Exhibits AB-1 and AB-2, and Ms. York did not file testimony.

Mr. Dauphinais's direct testimony consists of a cover page, a table of contents, 18 pages of questions and answers, and an appendix A setting out his qualifications; and along with his direct testimony, Mr. Dauphinais sponsored Exhibit AB-3. Mr. Dauphinais's

rebuttal testimony consists of a cover page, a table of contents, and 26 pages of questions and answers; and along with his rebuttal testimony, Mr. Dauphinais sponsored Exhibits AB-19 through AB-21.

Mr. Walters' direct testimony consists of a cover page, a table of contents, 74 pages of questions and answers, and an appendix A setting out his qualifications; and along with his direct testimony, Mr. Walters sponsored Exhibits AB-4 through AB-18. Mr. Walters' rebuttal testimony consists of a cover page, a table of contents, and five pages of questions and answers.

And Mr. Andrews submitted revised rebuttal testimony, consisting of a cover page, a table of contents, seven pages of questions and answers, and an appendix A setting out his qualifications; and along with his revised rebuttal testimony, Mr. Andrews sponsored Exhibit AB-23. And I just want to note that due to the revisions to his rebuttal testimony, there is no Exhibit AB-22.

JUDGE WALLACE: Thank you, Mr. Campbell. Is there any objection to binding in the direct and rebuttal testimony of Ms. York, Mr. Dauphinais, Mr. Andrews, Mr. Walters?

Hearing none, the direct and rebuttal

testimony of ABATE's witnesses is bound into the record.

Is there any objection to the admission of Exhibits AB-1, AB-2, AB-3, AB-4 through AB-18, AB-19 through AB-21, or AB-23?

Hearing none, those exhibits are admitted.

(Testimony bound in.)

- - -

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**

Direct Testimony and Exhibits of

Jessica A. York

On behalf of

Association of Businesses Advocating Tariff Equity

July 26, 2024

BRUBAKER & ASSOCIATES, INC.

Project 11638

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**

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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**

Direct Testimony of Jessica A. York

I. Introduction

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jessica A. York. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Association of Businesses Advocating Tariff Equity ("ABATE"). ABATE consists of large usage customers that purchase substantial amounts of electric power and/or delivery service from DTE Electric Company ("DTE"

or "Company"). They primarily take service under DTE Rate D8, Rate D11, Rider 3 and/or Rider 10.

Q PLEASE BRIEFLY SUMMARIZE ABATE'S WITNESSES IN THIS PROCEEDING AND THE ISSUES THEY ARE ADDRESSING IN DIRECT TESTIMONY.

A ABATE is providing direct testimony in this proceeding from three witnesses. They include myself and my colleagues James R. Dauphinais and Christopher C. Walters.

Mr. Dauphinais addresses: (i) DTE's use of a projected test year, (ii) DTE's proposed Investment Recovery Mechanism ("IRM") proposals in this proceeding, and (iii) the MISO Locational Marginal Price ("LMP") used for DTE's Rider 10.

In addition to summarizing the Direct Testimony of ABATE's witnesses in this proceeding, I address DTE's proposed projected test year Operation and Maintenance ("O&M") expense levels and DTE's proposal to include in its revenue requirement expenses for incentive compensation tied to its financial performance. I also address several of the capital expenditure amounts that DTE has projected it will incur either during its proposed projected test year or during the bridge period between the end of DTE's proposed historic year and beginning of its proposed projected test year.

Mr. Walters addresses DTE's proposed Return on Equity ("ROE").

Table JAY-1 summarizes ABATE's recommended downward adjustments to DTE's proposed revenue requirement increase. In total, ABATE's adjustments reduce DTE's proposed revenue requirement increase in this proceeding from $456.4 million down to $216.2 million. The Capital Expenditure adjustments in Table JAY-1 assume the Michigan Public Service Commission ("Commission") adopts Mr. Walters' rate of return recommendation of an authorized ROE of 9.6% at DTE's requested capital structure. If despite Mr. Walters' recommendation the Commission were to instead

adopt an authorized ROE greater than 9.6%, the listed downward revenue requirement adjustment associated with projected capital expenditures would be larger.

TABLE JAY-1

ABATE Revenue Requirement Adjustments
($ Millions)

Description	Amount
DTE Claimed Revenue Deficiency	$456.4
Adjustments:	
O&M (Inflation & Incentive Compensation)	$93.9
Projected Capital Expenditures[1]	$19.8
Depreciation & Property Taxes	$21.0
Return on Equity	$105.5
Total of ABATE Revenue Requirement Adjustments	$240.2
Adjusted Revenue Deficiency	$216.2

[1]This is at ABATE's recommended ROE of 9.6%. At DTE's proposed ROE of 10.50%, this adjustment would be $21.2 million.

My silence in this testimony, or that of my colleagues in their own testimonies, with regard to any issue should not be construed as an endorsement of DTE's position on that issue.

Q PLEASE BRIEFLY SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS IN THIS PROCEEDING.

A My conclusions and recommendations are as follows:

1. DTE in this proceeding is requesting to increase its electric rates by $456.4 million despite it reporting a revenue sufficiency of $80.5 million during its historical test year in this proceeding, a revenue sufficiency of $93.6 million during the historical test year of its most recent previous rate filing (Case No. U-21297) and a revenue

sufficiency of $111.7 million during the historical test year of its next most recent previous rate filing (Case No. U-20836).

2. For the reasons described by ABATE witness Mr. Dauphinais, the Commission should reject the use of a projected test year in this proceeding. It is also important to note that DTE's projected costs are not guaranteed to be incurred. However, if the Commission allows the use of projected costs, then at a minimum, the following adjustments should be made to DTE's projected test year amounts in this proceeding:

   a. DTE projects an inflation adjustment of $29.869 million for 2023 relative to 2022. However, DTE's actual 2023 O&M expense is known, and was $26.552 million less than the 2022 O&M expense. As a result, DTE's inflation adjustment of 3.2% for 2023 is unnecessary, and overestimates projected O&M for future years. I recommend no inflation adjustment be applied to project O&M for 2023.

   b. In addition, the inflation factors for 2024 and 2025 used to project DTE's future test year labor and non-labor O&M expense should reflect recent data for the Real Gross Domestic Product ("GDP") Chained Price Index, rather than outdated projections of the Consumer Price Index ("CPI") from October 2023. In total, my recommended modifications to DTE's inflation factors reduce DTE's projected test year O&M expense by $45.150 million.

   c. DTE's projected test year O&M expense includes $39.232 million of incentive compensation tied to financial performance. This amount should not be recovered from ratepayers, as it has not been shown to benefit customers.

   d. DTE's projected test year O&M expense includes $20.272 million tied to operational performance measures. Of this amount, $5.644 million is associated with programs for which the benefits to customers do not outweigh the costs. Thus, I recommend reducing DTE's projected test year O&M expense tied to operational performance by $5.644 million.

   e. In addition, $3.895 million of DTE's projected incentive compensation is associated with meeting or achieving target reliability indices (e.g., the System Average Interruption Duration Index ("SAIDI") excluding Major Event Days ("MEDs"), and the Customers Experiencing Multiple Interruptions ("CEMI4") percentage). The Company failed to achieve the target metrics in 2023, and there is a significant amount of uncertainty regarding whether it will do so in the projected test year. Therefore, I recommend reducing the Company's projected test year O&M expense by $3.895 million. It is unreasonable to recover the cost of this portion of incentive compensation through rates when the Company is not achieving its reliability goals and when it consistently has a revenue sufficiency based on historic test periods.

   f. I recommend that DTE's projected generation capital expenditures for the bridge period and test year be reduced by $52.969 million for the generation projects listed in Table JAY-3. Details supporting this recommendation are provided in Section III of this testimony.

g. I recommend that DTE's projected distribution capital expenditures for the bridge period and projected test year be reduced by $736.738 million, as shown in Table JAY-3. Details supporting this recommendation are provided in Section III of this testimony.

3. With these adjustments, along with those detailed in the Direct Testimony of ABATE witness Mr. Walters, at least $240.2 million (approximately 53%) of DTE's proposed $456.4 million rate increase in this proceeding is unwarranted, unsupported or both. As a minimum, this portion of DTE's proposed rate increase should be denied.

4. As detailed in the Direct Testimony of ABATE witness Mr. Dauphinais, DTE's proposed large expansion of the projected capital expenditures included in its already approved 2025 IRM should be rejected and its request to add two additional years, rather than one additional year to its IRM should be rejected as well.

5. As discussed in the Direct Testimony of Mr. Dauphinais, DTE's recent rate increases have been driven by the use of projected test years rather than historical test years for ratemaking and aggressive capital expenditures[1] coupled with the filing of frequent rate cases.

6. As detailed in the Direct Testimony of Mr. Dauphinais, based on DTE's track record with respect to the use of a projected test year, the Commission should reject DTE's proposed use of one in this proceeding and require DTE to use its proposed historical test year as the basis of its revenue requirement in this proceeding. Given that DTE is reporting a revenue sufficiency of $80.5 million for its historical test year in this proceeding, this would reject DTE's proposed rate increase in its entirety.

7. As detailed in the Direct Testimony of Mr. Dauphinais, if despite his recommendation, the Commission allows DTE to use a projected test year in this proceeding, the Commission should be vigilant to ensure the following: (i) that the projected expenses and investments included in DTE's projected test year are truly necessary to provide reliable electric service at lowest reasonable cost; (ii) that DTE is essentially irrevocably committed to incur them or otherwise cannot avoid them; and (iii) they are precisely quantified by DTE with respect to their amount and timing.

[1]With respect to capital expenditures, since at least Case No. U-18014, DTE in electric rate case applications has generally cited new investments in infrastructure as one of the largest, if not the largest, contributor to its requested rate relief. For example, in Case No. U-18014, DTE attributed $173 million of its requested rate relief of $344 million to investment-related costs (Case No. U-18014 Application at Paragraph 4 and Attachment 1 at Rate Base and Working Capital). Similarly, in Case No. U-20561, DTE attributed $219 million of its requested rate relief of $351 million to investment-related costs (Case No. U-20561 Rate Case Summary). In addition, in Case No. U-20836, Case No. U-21297 and the current proceeding (Case No. U-21534), DTE has indicated that the rate increase requests in those proceedings were, or are, being primarily driven by the Company's continued distribution infrastructure and generation investments (Case No. U-20836, January 18, 2022 Rate Case Summary at pages 1-2; Case No. U-21297, February 7, 2023 Rate Case Summary at page 2; and Case No. U-21534, March 25, 2024 Rate Case at page 2).

8. As detailed in the Direct Testimony of Mr. Dauphinais, DTE's Rider 10 should provide customers the ability to annually elect to use the MISO day-ahead energy LMP or the MISO real-time energy LMP.

II. O&M Expense

II.A. Inflation

Q PLEASE DISCUSS DTE'S HISTORICAL 2021 O&M EXPENSE AND THE AMOUNT OF O&M EXPENSE INCLUDED IN THE PROJECTED TEST YEAR ENDING NOVEMBER 2024.

A As shown in Exhibit A-13, Schedule C1, the adjusted historical test year level of O&M expense for 2022 is $1,224 million. DTE projects that O&M expenses will increase to $1,267 million for the test year ending December 2025. This represents an increase of $42.512 million, or about 3.5% relative to the 2022 historical level. However, this $42.512 million increase in O&M is comprised of $86.549 million of inflation adjustments in calendar year 2023 through December 2025, offset by a credit of $44.037 million for Other Adjustments.[2]

Q IS DTE'S PROJECTED TEST YEAR O&M EXPENSE REASONABLE?

A No. DTE's projected test year O&M expense is significantly overstated. First, 2023 actual costs are now available, so there is no need to project them based on a composite adjustment reflecting a 3.20% inflation factor and a 3.0% wage adjustment.[3] In addition, DTE's projected inflation adjustments from 2023 through December 2025 result in average annual increases in O&M expense that are significantly greater than the annual change in O&M expense that DTE has experienced over the last five years.

[2]Exhibit A-13, Schedule C5, line 12, columns (g) through (j).
[3]Exhibit A-13, Schedule C5.15.

Q PLEASE DISCUSS DTE'S PROJECTED LEVEL OF O&M EXPENSE FOR CALENDAR YEAR 2023.

A DTE's projected inflation adjustment for calendar year 2023 amounts to $29.869 million, or a 2.4% increase relative to the actual O&M expense incurred in 2022.[4] This is based on a composite inflation factor reflecting a 3.20% increase based on the CPI, and a 3% wage escalation factor.[5]

Adding DTE's projected adjustment of $29.869 million to its actual historical 2022 O&M expense yields projected O&M expense of $1.254 billion for calendar year 2023.

Q WHAT AMOUNT OF O&M EXPENSE DID DTE ACTUALLY INCUR IN CALENDAR YEAR 2023?

A DTE's actual O&M expense for calendar year 2023 was $1.197 billion.[6] Thus, DTE's projected 2023 O&M expense is overstated by $56.420 million ($1.254 billion - $1.197 billion). Rather than including an increase of $29.869 million in the bridge period for 2023 based on projected inflation rates, DTE's 2023 O&M expense should reflect a reduction of $26.552 million relative to 2022. However, to be conservative, I recommend resolving the discrepancy between DTE's actual and projected O&M expense for 2023 by eliminating DTE's proposed inflation adjustment for 2023.

[4]Exhibit A-13, Schedule C5, line 12, column (g) / line 12, column (f) = 2.4%.
[5]Exhibit A-13, Schedule C5.15.
[6]DTE's Response to Data Request ABDE-1.6. Attached as Exhibit AB-1, pages 1-2.

Q PLEASE DISCUSS DTE'S PROJECTED LEVEL OF O&M EXPENSE IN CALENDAR YEAR 2024 AND 2025.

A DTE's projected inflation adjustments for 2024 and 2025 are $27.935 million and $28.745 million, respectively.[7] These adjustments reflect composite factors based on a combination of inflation measured by the CPI (2.4% in 2024, and 2.2% for 2025),[8] and a 3.0% annual wage escalation factor.[9]

In total, DTE's projected 2024 O&M expense reflects about a 7.0%[10] increase over the 2023 actual O&M expense. DTE's projected O&M expense for 2025 reflects about a 2.2%[11] increase over the 2024 projected O&M expense. These projected increases significantly exceed the actual average annual increase in O&M expense experienced by DTE over the last several years.

Q PLEASE DISCUSS THE CHANGES IN O&M EXPENSE THAT DTE HAS EXPERIENCED OVER THE LAST FIVE YEARS.

A In Response to Discovery Request ABDE-1.6,[12] DTE provided actual O&M expenses from 2017 through 2023. DTE's actual O&M expenses are shown in Table JAY-2.

[7]Exhibit A-13, Schedule C5, line 12, columns (h) and (i).
[8]Exhibit A-13, Schedule C5.15.
[9]*Ibid.*
[10]Exhibit A-13, Schedule C5. (1,282,243 / 1,197,888) - 1 = 7.0%.
[11]Exhibit A-13, Schedule C5. (1,310,987) / (1,282,243) - 1 = 2.2%.
[12]Attached as Exhibit AB-1, pages 1-2.

TABLE JAY-2

Historical Changes in O&M Expense ($000)

Line	Calendar Year	Actual Historical Test Period O&M[1] (1)	Annual Change (2)	Adjusted Historical Test Period O&M[1] (3)	Annual Change (4)
1	2017	$1,426,289		$1,234,078	
2	2018	1,463,066	2.6%	1,269,157	2.8%
3	2019	1,440,617	-1.5%	1,260,934	-0.6%
4	2020	1,495,522	3.8%	1,258,887	-0.2%
5	2021	1,561,797	4.4%	1,290,029	2.5%
6	2022	1,528,528	-2.1%	1,224,440	-5.1%
7	2023	1,402,820	-8.2%	1,197,888	-2.2%
8	CAGR[2]		-0.3%		-0.5%

Sources and Notes:
[1] DTE's response to data request ABDE-1.6.
[2] Compound annual growth rate.

As shown in the table, DTE provided actual O&M expenses for each year, along with adjusted annual O&M expense which reflects ratemaking and normalization adjustments. The actual annual O&M expense increased by an average rate of 1.4% per year from 2017 to 2022, while the adjusted O&M expense decreased by an average rate of 0.2% per year. Including 2023 in the calculation of the compound annual growth rate shows that O&M expenses have declined slightly year-over-year. Importantly, both sets of data (actual and adjusted) show that despite inflationary pressures in 2022, DTE's actual O&M expense decreased by 2.1% relative to 2021, and its adjusted O&M expense decreased by 5.1%. DTE noted that 2023 was a financially challenging year.[13] However, DTE successfully managed its costs such that O&M decreased in 2023

[13] *Id.* at page 1.

relative to 2022, by deferring certain activities that did not impact the safety or reliability of electric service.[14]

This data shows that DTE is capable of managing its O&M expenses such that they do not change at the same rate as inflation. In addition, it reinforces the importance of carefully scrutinizing DTE's projections in each rate case.

Q HAS DTE REPRESENTED THAT IT HAS SUCCESSFULLY MANAGED ITS COSTS FOR MANY YEARS?

A Yes. DTE indicates that it strives to identify and execute sustainable productivity improvements and leverage new technology to help control the Company's cost structure over the long term, and that it has been able to offset inflation in prior years.[15] The Company notes that it is using its process improvement methodologies to hold costs below the inflation rate.[16] In addition, the data in Table JAY-2 supports the notion that the Company is capable of managing its O&M expenses such that they do not change at the same rate as inflation.

Q HAS DTE INCLUDED ANY REDUCTIONS TO ITS PROJECTED REVENUE REQUIREMENT IN THIS CASE TO REFLECT AN OFFSET TO WAGE GROWTH THAT MAY RESULT FROM PRODUCTIVITY GAINS?

A No. While DTE notes in its Response to ABATE's Discovery Request ABDE-1.9 that it has been able to offset inflation in prior years, it has not included any specifically identifiable offsets in this case.[17] The Company also indicated that it is using its process

[14] *Id.*
[15] DTE's Response to Data Requests ABDE-1.10, 1.11, and 1.12, attached as Exhibit AB-1, pages 3-5.
[16] *Ibid.*
[17] DTE's Response to Discovery Request ABDE-1.9. Attached as Exhibit AB-1 page 6.

improvement methodologies to hold costs below the inflation rate, but then claims that cost increases above the average inflation rate for base materials and qualified contract labor are expected to put pressure on its efforts.[18]

Q IS IT REASONABLE TO EXPECT THAT DTE WILL CONTINUE TO CONTROL OR MINIMIZE O&M IN A MANNER SUCH THAT THE TOTAL EXPENSES WILL CHANGE AT A RATE SLOWER THAN THE RATE OF INFLATION?

A Yes. As shown above, this has historically been the case. In addition, DTE proactively engages in a number of efforts to improve processes and reduce costs. In discovery responses cited earlier in this testimony, DTE explained that it strives to identify and execute sustainable productivity improvements and leverage new technology to help control the Company's cost structure over the long term. Further, the Company is expecting reductions in O&M expenses as a result of its proposed capital investments in the distribution system over the next five to ten years, and the transition of the generation fleet from coal to other alternatives.[19]

Q DO YOU HAVE ANY OTHER CONCERNS WITH RESPECT TO THE INFLATION RATES USED BY DTE TO PROJECT ITS TEST YEAR O&M EXPENSES?

A Yes. DTE's $86.549 million inflation adjustment has been estimated by the Company using a composite inflation rate based on a blend of: (1) the CPI-Urban ("CPI-U") published by S&P/IHS Markit; and (2) a projected wage inflation rate of 3.0% for both

[18]DTE's Response to Discovery Request ABDE-1.10. Attached as Exhibit AB-1, page 3.
[19]*Ibid.*

internal labor and contract labor.[20] DTE uses the 3.0% wage escalator for labor costs and the CPI for non-labor costs.[21]

DTE's CPI-U inflation rates were projected in October 2023,[22] and are now outdated. In addition, DTE's wage escalation assumption does not consider that certain escalations may be managed such that the expense may not increase at the overall cost of inflation.

Q HAVE YOU REVIEWED RECENT INFLATION PROJECTIONS FROM INDEPENDENT ECONOMISTS?

A Yes. More recent data indicates that inflation is lower than projected by DTE. For example, the Blue Chip Economic Indicators industry expert consensus Real GDP Chained Price Index shows 2.3% for 2024, and 1.8% for 2025.[23]

Q DO YOU AGREE WITH THE COMPANY'S ASSUMED LABOR ESCALATION FACTORS?

A No. There are many moving pieces with respect to the Company's labor expense. This includes changes in the number of new employees, which would potentially be brought on at lower wages than the average wage of existing employees, and recognizing that certain employees may retire over time and be replaced by new, less experienced, employees at lower wages. Mr. Cooper neglects to consider how these variables might impact the actual wage escalation.

[20]Revised Direct Testimony of Theresa Uzenski at Q/A 61.
[21]*Id.*
[22]Exhibit A-13, Schedule C5.15.
[23]Blue Chip Economic Indicators, June 10, 2024, page 5.

Moreover, it is more important to use projections of future escalators from independent economists. This is because independent economists have no interest in the outcome of this rate case.

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE INFLATION FACTORS USED TO PROJECT DTE'S TEST YEAR O&M EXPENSE?

A I recommend the projected inflation rates based on the Real GDP Chained Price Index be used to develop projected test year labor and non-labor O&M expense.

The Real GDP index uses a "chained" methodology. Each year, the basket of goods and services is updated to reflect what people are actually buying. This is unlike the CPI, which uses a fixed basket for a set period. This makes the Real GDP index more responsive to consumer substitution – if prices of certain goods rise, people might switch to less expensive alternatives, and the index will reflect that change. In addition, the CPI can be heavily weighted by the cost of medical expenses, which is not reflective of the cost of utility expenses.

This does not cure the deficiency for changes in the tenure of employees, but at least relies on independent factors to project escalations in labor costs. Further, this also does not consider the impact of productivity enhancements that will likely reduce escalation of actual costs to levels below the rate of inflation.

II.B. Incentive Compensation

Q PLEASE DISCUSS THE AMOUNT OF INCENTIVE COMPENSATION INCLUDED IN THE COMPANY'S REVENUE REQUIREMENT.

A The Company proposes to include $59.504 million of incentive compensation expense in the revenue requirement adopted by the Commission in this case.[24] This represents the portion of incentive compensation related to operating measures associated with the Annual Incentive Plan ("AIP") and Rewarding Employees ("REP"), and the total cost associated with the Long-Term Incentive Plan ("LTIP").[25]

Q OF THE $59.504 MILLION INCENTIVE COMPENSATION EXPENSE, WHAT PORTION IS ASSOCIATED WITH FINANCIAL PERFORMANCE?

A As shown in Table 3 of Mr. Cooper's Direct Testimony, the amount associated with financial performance is $39.232 million.[26]

Q IS IT REASONABLE TO INCLUDE ALL INCENTIVE COMPENSATION COSTS IN A COMPANY'S RATEMAKING COST OF SERVICE?

A No. Incentive compensation programs that are designed to align the interests of employees with shareholders should be paid for by shareholders. To the extent incentive compensation reflects customer-directed goals such as service reliability, and/or employee safety, only then is it arguably fair and reasonable to recover the costs of those programs from ratepayers, if the operational performance metrics are actually achieved.

[24]Direct Testimony of Michael Cooper at Q/A 93.
[25]*Ibid.*at Q/A 101.
[26]*Ibid.* at Q/A 120.

Q HAS THE COMMISSION PREVIOUSLY REJECTED THE INCLUSION OF INCENTIVE COMPENSATION RELATED TO FINANCIAL PERFORMANCE IN THE REVENUE REQUIREMENT?

A Yes. As noted in its May 8, 2020 Final Order in DTE's rate case, Case No. U-20561, for over a decade the Commission has unequivocally and consistently disallowed incentive compensation costs tied to financial measures.[27] In addition, the Commission indicated that it, "has been unwaveringly clear that incentive compensation tied to financial performance measures has not been shown to benefit ratepayers."[28] Similarly, in Case No. U-20836, the Commission found that, "incentive compensation tied to financial performance measures has not been shown to benefit ratepayers and thus should not be recovered through rates."[29]

Q HAS DTE PROVIDED EVIDENCE SHOWING THAT CUSTOMERS BENEFIT FROM INCENTIVE COMPENSATION TIED TO FINANCIAL PERFORMANCE METRICS?

A No. As shown on DTE's Exhibit A-21, Schedule K-6, the costs associated with financial performance outweigh the benefits to customers in six out of seven metrics, and cost $39.232 million but only provide $19.946 million in benefits to customers.[30]

[27]Case No. U-20561, May 8, 2020 Final Order at page 17.
[28]*Ibid.* at 19.
[29]Case No. U-20836, November 18, 2022 Final Order at page 301.
[30]Exhibit A-21, Schedule K6, line 16, columns (k) and (l).

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE INCENTIVE COMPENSATION RELATED TO FINANCIAL PERFORMANCE?

A I recommend the Commission reject DTE's proposal to include $39.232 million of incentive compensation in the revenue requirement adopted in this case, consistent with its findings in prior cases.

Q DO YOU HAVE CONCERNS WITH ANY OF THE INCENTIVE COMPENSATION TIED TO OPERATIONAL PERFORMANCE MEASURES?

A Yes. Mr. Cooper notes that the Commission has indicated in all its recent Orders addressing incentive compensation programs that inclusion of incentive compensation expense in a company's revenue requirement was dependent on a showing that the incentive compensation programs provided benefits to customers in excess of the expense.[31] However, as shown on Exhibit A-21, Schedule K-6, there are certain components of the operational performance measures for which the benefits do not exceed the expense. For example, the expense associated with Customer Satisfaction measures is $5.848 million, but the benefit is only $2.264 million. Similarly, the benefits do not outweigh the expenses related to certain Safety & Engagement measures (e.g., OSHA Recordable Incident Rate, DTE Energy High Energy Serious Injury or Fatality, Nuclear Total Industrial Safety Accident Events, and Nuclear On-Line Radiation Exposure). In total, the expenses of these programs exceed the benefit by $5.644 million.

Further, the Company's projected incentive compensation levels include $1.937 million for meeting target values for SAIDI excluding MEDs, and $1.958 million

[31]Direct Testimony of Mr. Cooper at Q/A 125.

for CEMI4.[32] The Company did not achieve the target values for these metrics in 2023, and it is not reasonably certain the Company will do so during the future test year. Specifically, the target SAIDI excluding MEDs in 2023 was 150 minutes,[33] but the Company achieved 157 minutes.[34] In addition, the target CEMI4 percentage was 7.55%,[35] but the Company achieved 13.38%.[36] In light of the Company's recent failure to meet its reliability goals, as well as its track record of historic revenue sufficiency amounts, the incentive compensation associated with achieving these distribution reliability metrics should not be recovered from ratepayers.

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE INCENTIVE COMPENSATION RELATED TO OPERATIONAL PERFORMANCE?

A I recommend, that at a minimum, the Company's projected test year incentive compensation expense tied to operational performance measures be reduced by a total of $9.539 million (i.e., the sum of $5.644 million, $1.937 million, and $1.958 million).

Q PLEASE SUMMARIZE YOUR RECOMMENDATION WITH RESPECT TO DTE'S TOTAL PROJECTED TEST YEAR O&M EXPENSES.

A My recommended inflation adjustments reduce DTE's projected O&M expense by $45.2 million, and my recommended adjustment to DTE's projected incentive compensation expense reduces test year O&M by $48.8 million. In total, my

[32]Exhibit A-21, Schedule K6.
[33]Direct Testimony of Mr. Cooper at Q/A 111.
[34]Case No. U-12270. DTE's 2023 MPSC Service Quality and Reliability Standards Annual Report. PDF at page 4.
[35]Direct Testimony of Mr. Cooper at Q/A 111.
[36]Case No. U-12270. DTE's 2023 MPSC Service Quality and Reliability Standards Annual Report. PDF at page 2.

recommendations would reduce DTE's projected test year O&M expense by about $93.9 million.

III. Capital Expenditures and Rate Base

Q PLEASE SUMMARIZE DTE'S PROPOSED LEVEL OF CAPITAL EXPENDITURES ADDED TO RATE BASE.

A As shown on Exhibit A-12, Schedule B-1, DTE proposes a rate base level of $22.108 billion for the projected test year. This represents an increase of about $1.991 billion, or 9.9%, relative to the historical 2022 test year level of $20.117 billion. The increase in rate base is primarily driven by $7.857 billion[37] of new capital expenditures proposed by DTE during the 36-months ending December 2025.

Q HAVE YOU IDENTIFIED SPECIFIC AREAS WHERE CAPITAL EXPENDITURES CAN BE REDUCED?

A Yes. I have reviewed DTE's forecasted capital expenditures by major department or functional area and have identified adjustments that would result in expenditure levels that are more reasonable than those proposed by DTE. These adjustments and the overall impact on rate base are summarized in Table JAY-3 and are described below in greater in detail.

[37]Exhibit A-12, Schedule B5, line 13, sum of columns (e) and (f).

TABLE JAY-3

ABATE Proposed
Capital Expenditure Adjustments ($000)

Line	Description	DTE Proposed	ABATE Proposed	ABATE More / (Less) than DTE Amount	Percent
	Generation (Non-Routine)				
1	Trenton Channel Sea Wall	$ 10,934	$ -	$ (10,934)	-100.0%
2	River Rouge Decommissioning (Major)	33,956	29,548	(4,408)	-13.0%
3	Blackstart Project 10570 & 20255	12,633	-	(12,633)	-100.0%
4	Blackstart Project 17611	8,102	-	(8,102)	-100.0%
5	Blackstart Project 18320	4,445	-	(4,445)	-100.0%
	Generation (Routine)				
6	Blackstart Peaker Unit 2 Starting System	$ 2,795	$ -	$ (2,795)	-100.0%
7	Blackstart Unit Major Overhaul	6,376	-	(6,376)	-100.0%
	BWEC Conference Room Building	3,275	-	(3,275)	-100.0%
8					
	Distribution				
9	Base Capital	$ 2,435,669	$ 2,312,787	$(122,882)	-5.0%
10	Strategic Capital	2,337,083	1,723,227	(613,856)	-26.3%
11	Totals	$ 4,855,269	$ 4,065,562	$(789,707)	-16.3%
12	Projected Test Year Rate Base	$22,107,989	$21,820,727	$(287,262)	-1.3%

Q PLEASE EXPLAIN WHY REDUCING DTE'S PROJECTED CAPITAL EXPENDITURES BY $0.790 BILLION RESULTS IN AN APPROXIMATE $0.287 BILLION REDUCTION TO TOTAL RATE BASE.

A Rate base primarily consists of utility plant-in-service, offset by accumulated depreciation. DTE's projected plant-in-service for the test year was calculated as the simple average of utility plant-in-service as of December 2024 and December 2025 (i.e., December 2024 plant-in-service plus December 2025 plant-in-service, divided by 2).

I have approximated the impact of my recommended capital expenditures based on this averaging approach, including the impact of accumulated depreciation. Note, however, that the exact impact would depend on the timing of when the various projects are placed into service.

III.A. Production Capital Expenditures

Q WHAT LEVEL OF CAPITAL EXPENDITURES HAS DTE PROPOSED FOR ITS PRODUCTION OPERATIONS?

A As shown on DTE's Exhibit A-12, Schedule B-5, DTE forecasts about $1.507 billion[38] of capital expenditures for production plant, excluding nuclear. I recommend adjustments to DTE's proposed capital expenditures for several projects, as described throughout the next several sections of this testimony.

III.A.i. Trenton Channel Sea Wall

Q PLEASE SUMMARIZE DTE'S PROPOSAL WITH RESPECT TO THIS PROJECT.

A The Trenton Channel Sea Wall project entails restoring the integrity of the seawall at the Trenton Channel Power Plant and the installation of a pedestrian greenway path along the Detroit River.[39] DTE proposes to include in rate base $1.427 million in the

[38]Exhibit A-12, Schedule B5, sum of columns (e) and (f), lines 2 through 5.
[39]Revised Direct Testimony of Margaret Guillaumin at Q/A 50.

bridge period, and $9.507 million in the projected test year for this project.[40] The Company has provided an Appropriation Request in support of this project.[41]

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE TRENTON CHANNEL SEA WALL PROJECT?

A The Appropriation Request document provided by DTE is for $1.1 million in 2022 and 2023, and does not support the level of expenditures shown in the Company's Exhibit A-12, Schedule B5.1. Thus, the Company's proposed expenditures for this project should not be included in rates at this time.

III.A.ii. River Rouge Decommissioning (Major)

Q WHAT LEVEL OF CAPITAL EXPENDITURES HAS DTE INCLUDED IN THE BRIDGE PERIOD AND THE PROJECTED TEST YEAR FOR THE RIVER ROUGE DECOMMISSIONING PROJECT?

A As shown on Exhibit A-12, Schedule B5.1, page 2 of 8, DTE includes $33.956 million in the bridge period for this project. This is comprised of $21.148 million in 2023, and $12.808 million in 2024.[42]

Q PLEASE DESCRIBE THIS PROJECT.

A DTE testifies that this project is to fully decommission and remove all plant structures including waste products from the site, to achieve a cold, dark, and dry status by the end of 2024.[43] The testimony claims it expects to spend $12.808 million in 2024 to

[40]Exhibit A-12, Schedule B5.1 page 2 of 9.
[41]Attached as Exhibit AB-2 at pages 1-2.
[42]*Id.*
[43]Revised Direct Testimony of Margaret Guillaumin at Q/A 47.

complete this project. However, in support of this project, the Company has provided an Appropriation Request document, which shows expenditures of $8.4 million in 2024.[44]

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO DTE'S PROJECTED CAPITAL EXPENDITURES FOR THIS PROJECT?

A I recommend the projected capital expenditures for this project be reduced to $8.4 million in 2024, to be consistent with the supporting documents provided by DTE.

III.A.iii. Blackstart Projects

Q PLEASE DISCUSS DTE'S PROPOSED BLACKSTART PROJECTS.

A DTE proposes to include in rates the total capital expenditures of $25.181 million, for four blackstart projects.[45] DTE indicates that these projects support the North American Reliability Corporation ("NERC") black start plan, but it cannot disclose details, in order to maintain the integrity of these sites.[46]

Q HAS DTE PROVIDED DOCUMENTS SUPPORTING THESE PROJECTS?

A DTE provided several Project Management and Planning ("PMP") documents to support these projects.[47] However, the information describing the scope of the projects and timelines is redacted in the PMP documents included in DTE's workpapers. It does not appear that unredacted copies were provided, even to parties that executed the Nondisclosure Certificate in this rate case.

[44]Attached as Exhibit AB-2 at pages 3-5.
[45]Exhibit A-12, Schedule B5.1, page 2, lines 37-39, columns (e) and (f).
[46]Revised Direct Testimony of Margaret Guillaumin at Q/A 54.
[47]PMP 10570, 20255, 17611, and 18320. Attached as Exhibit AB-2, pages 6-9.

Further, the PMP documents indicate that they have been revised and/or the project schedules have changed. However, due to the redactions, it is unclear what revisions have been made, the reasoning behind such revisions, or whether schedule changes affect the likelihood of these projects being completed as planned during the bridge period or projected test year in this case. In addition, the testimony provides limited information about the status of these projects, and execution of project tasks and timelines in 2023 through 2025.

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THESE PROJECTS?

A DTE has provided minimal information to support the inclusion of these projects in the bridge period and projected test year in this case. Thus, I recommend the Commission disallow all projected capital expenditures associated with these projects from rate base. While the Commission found in DTE's last rate case (Case No. U-21297) that these types of projects were important to maintain grid security,[48] ratepayers should not be responsible for unsubstantiated costs that have not been demonstrated to be reasonably likely to be incurred by DTE in the bridge period or projected test year.

III.A.iv. Blackstart Peaker Unit 2 Starting System

Q WHAT LEVEL OF CAPITAL EXPENDITURES HAS DTE INCLUDED IN THE BRIDGE PERIOD AND THE PROJECTED TEST YEAR FOR THIS PROJECT?

A The Company proposes to include in rate base $2.795 million of projected capital expenditures in 2025 for this project.[49] The Company indicates that the unit starting

[48]Case No. U-21297, December 1, 2023 Order at page 43.
[49]Exhibit A-12, Schedule B5.1, page 7 of 9.

system is obsolete and requires replacement with an up-to-date design.[50] In support of this project, the Company provided PMP 19737.[51]

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THIS PROJECT?

A I recommend the projected capital expenditures for this project be excluded from rates at this time. The supporting document for this project is redacted. This means parties cannot independently review and assess the scope of this project, the project timelines, or any revisions that have occurred. In addition, the supporting document shows that the projected cost has changed from $50,000 to $3.245 million without explanation.

III.A.v. Blackstart Unit Major Overhaul

Q WHAT LEVEL OF CAPITAL EXPENDITURES HAS DTE INCLUDED IN THE BRIDGE PERIOD AND THE PROJECTED TEST YEAR FOR THIS PROJECT?

A The Company proposes to include in rate base $6.376 million of projected capital expenditures in 2025 for this project.[52] The Company indicates that a major unit overhaul outage will begin and be completed in 2026, and that the work is required for continued safe and reliable operation.[53] In support of this project, the Company provided PMP 18090.[54]

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THIS PROJECT?

A I recommend the projected capital expenditures for this project be excluded from rates at this time. The supporting document for this project is redacted. This means parties

[50]Revised Direct Testimony of Margaret Guillaumin at Q/A 85.
[51]Attached as Exhibit AB-2 at page 10.
[52]Exhibit A-12, Schedule B5.1, page 7 of 9.
[53]Revised Direct Testimony of Margaret Guillaumin at Q/A 85.
[54]Attached as Exhibit AB-2 at page 11.

cannot independently review and assess the scope of this project, the project timelines, or any revisions that have occurred. In addition, the supporting document shows that a schedule change has occurred, but there is no explanation as to what the change was, why it occurred, or whether the project is likely to be complete during the bridge period or projected test year in this case.

III.A.vi. Blue Water Energy Center Conference Room Building

Q WHAT LEVEL OF CAPITAL EXPENDITURES HAS DTE INCLUDED IN THE BRIDGE PERIOD AND THE PROJECTED TEST YEAR FOR THIS PROJECT?

A The Company proposes to include in rate base $3.275 million of projected capital expenditures in 2024 for a conference room building at the Blue Water Energy Center.[55] In support of this proposal, DTE notes that at times, the number of workspaces in the current office space configuration are not sufficient because the site workforce can surge in support of routine and major maintenance activities.[56] The Company also notes that other DTE power plant sites have repurposed original construction buildings that were converted to functional plant conference rooms when construction was complete.

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THIS PROJECT?

A I recommend the projected capital expenditures for this conference room building be excluded from rate base, as they were in the last rate case.[57] The Company has not adequately justified the cost or the necessity of the new conference room building. DTE

[55]Revised Direct Testimony of Margaret Guillaumin at Q/A 84.
[56]*Id.*
[57]Case No. U-21297, December 1, 2023 Order at pages 36-38.

has not explained why adequate office space was not included in the original design of the Blue Water Energy Center if all of the Company's power plant facilities require such conference facilities.

III.B. Distribution Capital Expenditures

Q WHAT LEVEL OF CAPITAL EXPENDITURES HAS DTE PROPOSED FOR ITS DISTRIBUTION OPERATIONS?

A As shown on DTE's Exhibit A-12, Schedule B-5, DTE forecasts about $4.773 billion[58] of capital expenditures for distribution plant during the bridge period and projected test year. My recommended adjustments to DTE's proposed distribution capital expenditures are discussed below in greater detail.

Q DO YOU HAVE ANY CONCERNS WITH DTE'S PROJECTED DISTRIBUTION CAPITAL EXPENDITURES GENERALLY?

A Yes. As shown on Exhibit A-12, Schedule B-5, distribution investment is becoming an increasingly larger portion of DTE's total capital expenditures. As shown on that exhibit, in 2022, distribution capital expenditures represented about 57.7%[59] of total capital expenditures. DTE's projections show that this percentage grows to 59.8%[60] during the bridge period, and increases to 62.7%[61] in the projected test year. Further, the projected capital expenditures DTE proposes to include in rate base in this case include several projects that are not projected to be placed in-service until well beyond the end of the future test year, including as far into the future as December 1, 2035.

[58]Exhibit A-12, Schedule B5, sum of columns (e) and (f), line 7.
[59]Compares distribution capital expenditures from Exhibit A-12, Schedule B5, line 7 to line 13.
[60]*Id.*
[61]*Id.*

DTE's distribution investment is geared toward improving system reliability and resiliency. However, despite DTE's growing investment in the distribution system, DTE's system reliability metrics have not significantly improved in recent years. This is shown in DTE's Exhibit A-23, Schedule M-8, at pages 40-41 and 207-208. In addition, as noted earlier in this testimony, DTE failed to meet its target SAIDI and CEMI4 metrics in 2023. As a result, the Commission should closely scrutinize the Company's projected distribution capital expenditures to ensure that the interests of DTE and its ratepayers are reasonably balanced.

Q ARE YOU PROPOSING ANY ADJUSTMENTS TO THE LEVEL OF DISTRIBUTION CAPITAL EXPENDITURES DTE PROPOSES TO INCLUDE IN RATE BASE?

A Yes. I am recommending adjustments to the level of capital expenditures projected by DTE for emergent replacements and strategic capital programs.

III.B.i. Emergent Replacements

Q WHAT IS DTE'S PROPOSED LEVEL OF CAPITAL EXPENDITURES FOR EMERGENT REPLACEMENTS?

A DTE requests to include in rate base $1.531 billion of capital expenditures for emergent replacements.[62] This category includes storm, non-storm, and substation reactive investments. Storm-related emergent replacements include investments required to perform repairs and replacements of the overhead and underground distribution and subtransmission systems for damage which occurs during storms.[63] Non-storm emergent replacements include investments required to return the overhead and

[62]Exhibit A-12, Schedule B5.4, page 1, line 7, sum of columns (e) and (f).
[63]Direct Testimony of Brian Hill at Q/A 13.

underground distribution systems, and subtransmission electrical system to restore power and/or return to normal operating configuration during non-storm conditions.[64] DTE developed its projections for each of these components based on a five-year average of inflation adjusted emergent replacement capital expenditures from 2018 through 2022.[65] The substation reactive category includes spending required to perform emergency replacement work for substation equipment.[66]

Q DO YOU AGREE WITH DTE'S PROPOSED USE OF A FIVE-YEAR AVERAGE OF HISTORICAL EMERGENT CAPITAL SPENDING AS THE BASIS TO PROJECT CAPITAL EXPENDITURES DURING THE BRIDGE PERIOD AND PROJECTED TEST YEAR?

A No. While the five-year average has historically been approved by the Commission, it is inappropriate to rely on a five-year average in this case. Specifically, 2021 data should not be included in the historical average, as it was an abnormal year in terms of storm activity. DTE's testimony in its last rate case acknowledged that in 2021 the Company experienced 12 storm events that, when combined, were unprecedented in the Company's history, in terms of frequency, intensity, and number of outages for customers.[67] This unprecedented nature of 2021 is also evident from a review of expenditures on storm-related emergent replacements shown on Exhibit A-12, Schedule B5.4, at page 3. In 2021, these expenditures more than doubled relative to DTE's annual expenditures from 2018 through 2020. In 2022, the number of storm

[64] *Ibid.* at Q/A 21.
[65] *Ibid.* at Q/A 15 and Q/A 23.
[66] *Ibid.* at Q/A 25.
[67] Case No. U-21297, Direct Testimony of Brian Hill at Q/A 23.

days was lower than DTE projected, and there was only one catastrophic storm, which was also lower than the Company's internal forecast.[68]

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO DTE'S PROJECTED CAPITAL EXPENDITURES FOR EMERGENT REPLACEMENTS?

A I recommend that DTE rely on a four-year average of historical expenditures from 2018-2022, excluding 2021 as the basis for its projections of storm-related emergent replacements going forward. As discussed above, 2021 was an unprecedented year for emergent replacements, and relying on 2021 as the basis for future projections only serves to unnecessarily inflate DTE's projected capital expenditures in this case. DTE has not provided evidence suggesting that the bridge period or projected test year will require emergent replacements that significantly exceed the four-year average referenced above. Further, the inflation adjustments used to project emergent replacements (and all base capital expenditures) should be updated to reflect the Real GDP Chained Price Index as discussed earlier in this testimony in the context of O&M expenses.

Q WHAT IS THE IMPACT ON DTE'S PROPOSED CAPITAL EXPENDITURES FOR BASE CAPITAL PROGRAMS IF A FOUR-YEAR AVERAGE AND YOUR RECOMMENDED INFLATION ADJUSTMENTS ARE USED, RATHER THAN THE METHODOLOGY PROPOSED BY DTE?

A If a four-year average (2018-2020 and 2022) of actual historical capital investment is used for storm-related emergent replacements, and my recommended inflation factors

[68] *Ibid.* at Q/A 21.

are applied, the total Base Capital expenditure amount would be reduced by $122.882 million.

III.B.ii. Strategic Replacements

Q WHAT LEVEL OF CAPITAL EXPENDITURES HAS DTE PROPOSED FOR ITS STRATEGIC CAPITAL PROGRAMS?

A As shown on DTE's Exhibit A-12, Schedule B5.4, page 1, DTE forecasts $1,036 million of capital expenditures for Infrastructure Resilience and Hardening, $777.742 million for Infrastructure Redesign and Modernization, and $523.095 million for Technology and Automation. This represents a total of $2.337 billion of projected expenditures for this investment category.

Q DO YOU AGREE WITH THIS LEVEL OF CAPITAL EXPENDITURES FOR THE STRATEGIC CAPITAL PROGRAMS CATEGORY?

A No. I agree that DTE needs to uphold its commitment to investing in its Strategic Capital Programs to improve system resiliency and reliability. However, as explained above, the system reliability metrics have exhibited minimal improvement in recent years. In addition, DTE has a history of underspending on Strategic Capital Programs relative to its forecasts, as those funds have historically been diverted to emergent replacements.[69] Further, DTE's proposed spending on these programs includes significant levels of capital expenditures for projects that are not expected to be placed in-service until after the end of the projected test year in this case. Specifically, Exhibit A-12, Schedule B5.4, pages 8 through 12 show that several projects are expected to be in-service at various dates ranging from December 31, 2026 through

[69]Case No. U-20836, Pfeuffer Direct at Q/A 28; Case No. U-20561, 4 Tr. 131-132.

December 31, 2035, and therefore, will not become used and useful during the bridge period or projected test year.

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO DTE'S PROJECTED INVESTMENT IN STRATEGIC CAPITAL PROGRAMS?

A For the reasons described above, including the lackluster improvement to system reliability metrics, I recommend the Commission allow only the projected capital expenditures associated with projects that are expected to be in-service during the bridge period and projected test year. This results in inclusion of $1.723 billion of capital expenditures for Strategic Capital Programs, which is a reduction of $613.586 million relative to the amount proposed by the Company, but is still about 2.5x the amount reportedly spent in 2022.[70]

Q PLEASE IDENTIFY THE REVENUE REQUIREMENT IMPACT OF YOUR PROPOSED ADJUSTMENTS TO DTE'S PROJECTED CAPITAL EXPENDITURES.

A My recommendations reduce DTE's projected generation and distribution capital expenditures by $0.790 billion. This reduces the total rate base by an estimated $0.287 billion. Multiplying the reduction in the rate base by DTE's pre-tax rate of return of 7.37%[71] reduces DTE's claimed revenue deficiency by $21.2 million. Based on the 9.6% ROE supported by Mr. Walters, the revenue requirement impact of my adjustments would be $19.8 million.

[70]Exhibit A-12, Schedule B5.4, page 1, column (b), line 22.
[71]DTE's Exhibit A-14, Schedule D1.

Q PLEASE IDENTIFY THE TOTAL REVENUE REQUIREMENT IMPACT OF ALL OF YOUR RECOMMENDED ADJUSTMENTS.

A As noted above, the revenue requirement impact of my proposed adjustments to DTE's capital expenditures is $21.2 million, using DTE's proposed ROE of 10.50%. Adding my adjustments for O&M expense, depreciation, and property taxes results in a total revenue requirement reduction of $136.0 million. However, at Mr. Walters' recommended ROE of 9.6%, my adjustments reduce DTE's claimed revenue deficiency by $134.7 million. This result is summarized in Table JAY-4.

TABLE JAY-4

ABATE's
Requirement Adjustments ($ Millions)

Line	Description	DTE ROE	ABATE ROE
1	Return on Rate Base	$ 21.2	$ 19.8
2	Depreciation	14.9	14.9
3	Property Taxes	6.1	6.1
4	Incentive Comp.	48.8	48.8
5	O&M Inflation	45.2	45.2
6	Total Adjustments	$ 136.0	$ 134.7

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Jessica A. York

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jessica York. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE IDENTIFY THE JURISDICTIONS IN WHICH YOU HAVE PREVIOUSLY SPONSORED TESTIMONY.

A I have sponsored expert testimony in front of the Idaho Public Utilities Commission, the Illinois Commerce Commission, Indiana Utility Regulatory Commission, the Michigan Public Service Commission, the Minnesota Public Utilities Commission, the Missouri Public Service Commission, the Public Utilities Commission of Nevada, the Oklahoma Corporation Commission, the Virginia State Corporation Commission, and the Public Service Commission of Wisconsin.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A I graduated from Truman State University in 2008 where I received my Bachelor of Science Degree in Mathematics with minors in Statistics and Actuarial Science. I earned my Master of Business Administration Degree with a concentration in Finance from the University of Missouri-St. Louis in 2014.

I joined BAI in 2011 as an analyst. Then, in March 2015, I joined the consulting team of BAI.

I have worked in various electric, natural gas and water and wastewater regulatory proceedings addressing cost of capital, sales revenue forecasts, revenue requirement assessments, class cost of service studies, rate design, and various policy issues. I have also conducted competitive power and natural gas solicitations on behalf of large electric and natural gas users, have assisted those large power and natural gas users in developing procurement plans and strategies, assisted in competitive contract negotiations, and power and natural gas contract supply administration. In the regulated arena, I have evaluated cost of service studies and rate designs proffered by other parties in cases for various utilities, including in Idaho, Illinois, Indiana, Kansas, Wisconsin and others. I have conducted bill audits, rate forecasts and tariff rate optimization studies.

I have also provided support to clients with facilities in deregulated markets, including drafting supply requests for proposals, evaluating supply bids, and auditing competitive supply bills. I have also prepared and presented to clients reports that monitor the electric market and recommend strategic hedging transactions.

BAI was formed in April 1995. BAI and its predecessor firm have participated in more than 700 regulatory proceedings in forty states and Canada.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation.

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

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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**

Direct Testimony and Exhibit of

James R. Dauphinais

On behalf of

Association of Businesses Advocating Tariff Equity

July 26, 2024

BRUBAKER & ASSOCIATES, INC.

Project 11638

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**

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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**

Direct Testimony of James R. Dauphinais

I. Introduction

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James R. Dauphinais. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Association of Businesses Advocating Tariff Equity ("ABATE"). ABATE consists of large usage customers that purchase substantial

amounts of electric power and/or delivery service from DTE Electric Company ("DTE" or "Company"). They primarily take service under DTE Rate D8, Rate D11, Rider 3 and/or Rider 10.

Q HAVE YOU PRESENTED TESTIMONY IN PRIOR ELECTRIC REGULATORY PROCEEDINGS BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION ("COMMISSION")?

A Yes. Over my 27 years of employment by BAI, I have provided testimony to the Commission on several occasions regarding issues that include revenue requirement, electric rate design, class cost of service, power supply cost recovery, resource planning, standby service rates, transmission planning and transmission line routing. In recent years this has included providing testimony in: (i) the most recent general electric rate cases of Consumers Energy Company (Case No. U-20963, U-21224 and U-21389), DTE (Case Nos. U-18014, U-18255, U-20162, U-20561, U-20836 and U-21297) and Indiana Michigan Power Company (Case Nos. U-18370, U-20359 and U-21461); (ii) the original Section 6w State Reliability Mechanism ("SRM") Capacity Charge proceedings of Consumers Energy Company (Case No. U-18239) and DTE (Case No. U-18248); and (iii) the most recent Integrated Resource Plan cases proceedings of Consumers Energy Company (Case No. U-21090), DTE (Case No. U-21193), and Indiana Michigan Power Company (Case No. U-21189).

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A My testimony will address: (i) DTE's use of a projected test year, (ii) DTE's proposed Investment Recovery Mechanism ("IRM") proposals in this proceeding, and (iii) the MISO Locational Marginal Price ("LMP") used DTE's Rider 10.

My silence with regard to any position taken by DTE in its application or direct testimony in this proceeding does not indicate my endorsement of that position.

Q PLEASE BRIEFLY SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS IN THIS PROCEEDING.

A My conclusions and recommendations are as follows:

1. DTE is requesting to increase its electric rates by $456.4 million despite it reporting a revenue sufficiency of $80.5 million during its historical test year in this proceeding, a revenue sufficiency of $93.6 million during the historical test year of its most recent previous rate filing (Case No. U-21297) and a revenue sufficiency of $111.7 million during the historical test year of its next most recent previous rate filing (Case No. U-20836).

2. DTE's proposed large expansion of the projected capital expenditures included in its approved Year 2 (2025) distribution IRM should be rejected and its request to add two additional years, rather than one additional year, to its distribution IRM should be rejected as well.

3. To the extent the Commission in this proceeding authorizes a Year 3 for DTE's distribution IRM, the included investments should be limited to the existing "Conversions," "Subtransmission Redesign and Rebuild," "Breaker Replacement" and "URD Replacement" categories in a total amount not to exceed $275.0 million.

4. As discussed in my testimony herein DTE's recent rate increases have been driven by the use of projected rather than historical test years for ratemaking and aggressive capital expenditures[1] coupled with the filing of frequent rate cases.

5. As detailed in my testimony herein, based on DTE's track record with respect to the use of a projected test year, the Commission should reject DTE's proposed use of one in this proceeding and require DTE to use its proposed historical test year as the basis of its revenue requirement in this proceeding. Given that DTE is reporting a revenue sufficiency of $80.5 million for its historical test year in this proceeding, this would eliminate DTE's proposed rate increase in its entirety.

[1]With respect to capital expenditures, since at least Case No. U-18014, DTE in electric rate case applications has generally cited new investments in infrastructure as one of the largest, if not the largest, contributor to its requested rate relief. For example, in Case No. U-18014, DTE attributed $173 million of its requested rate relief of $344 million to investment-related costs (Case No. U-18014 Application at Paragraph 4 and Attachment 1 at Rate Base and Working Capital). Similarly, in Case No. U-20561, DTE attributed $219 million of its requested rate relief of $351 million to investment-related costs (Case No. U-20561 Rate Case Summary). In addition, in Case No. U-20836, Case No. U-21297 and the current proceeding (Case No. U-21534), DTE has indicated that the rate increase requests in those proceedings were, or are, being primarily driven by the Company's continued distribution infrastructure and generation investments (Case No. U-20836, January 18, 2022 Rate Case Summary at 1-2; Case No. U-21297, February 7, 2023 Rate Case Summary at 2; and Case No. U-21534, March 25, 2024 Rate Case at 2).

6. As detailed in my testimony herein, if despite my recommendation, the Commission allows DTE to use a projected test year in this proceeding, the Commission should be vigilant to ensure the following: (i) that the projected expenses and investments included in DTE's projected test year are truly necessary to provide reliable electric service at lowest reasonable cost; (ii) that DTE is essentially irrevocably committed to incur them or otherwise cannot avoid them; and (iii) they are precisely quantified by DTE with respect to their amount and timing.

7. DTE's Rider 10 should be such that each Rider 10 customer has the ability to annually elect to use the MISO day-ahead energy LMP or the MISO real-time energy LMP.

II. Projected Test Year

Q YOU HAVE ALLEGED THAT, ALONG WITH THE PURSUIT OF AGGRESSIVE CAPITAL EXPENDITURES, DTE'S USE OF A PROJECTED TEST YEAR IS A MAJOR DRIVER OF DTE'S PROPOSED RATE INCREASE IN THIS PROCEEDING. PLEASE EXPLAIN WHY THIS IS THE CASE.

A The best starting point for exploring this issue is to compare DTE's own historical and projected test year calculations for this case and its six most recent general rate cases. I present this comparison below in Table JRD-1.

TABLE JRD-1

Historical Test Year and Projected Test Year

Rate Sufficiency / (Deficiency)

Case	Year Filed	Historical Test Year Sufficiency / (Deficiency)	Projected Test Year Sufficiency / (Deficiency)	Difference Between Historical and Projected
U-18014	2016	$33,404,000	($343,972,000)	($377,376,000)
U-18255	2017	($50,009,000)	($230,942,000)	($180,933,000)
U-20162	2018	($18,335,000)	($328,440,000)	($310,105,000)
U-20561	2019	($111,501,000)	($350,688,000)	($239,187,000)
U-20836	2022	$111,696,000	($388,222,000)	($499,918,000)
U-21297	2023	$93,577,000	($618,536,000)	($712,113,000)
U-21534	2024	$80,492,000	($456,434,000)	($536,926,000)
Total		$139,324,000	($2,717,234,000)	($2,856,558,000)

Sources:
Case No. U-18014, Exhibit A-1 and Exhibit A-8, Schedule A1
Case No. U-18255, Exhibit A-1 and Exhibit A-8, Schedule A1
Case No. U-20162, Exhibit A-1 and Exhibit A-11, Schedule A1
Case No. U-20561, Exhibit A-1 and Exhibit A-11, Schedule A1
Case No. U-20836, Exhibit A-1 and Exhibit A-11, Schedule A1
Case No. U-21297, Exhibit A-1 and Exhibit A-11, Schedule A1
Case No. U-21534, Exhibit A-1 and Exhibit A-11, Schedule A1

What this shows is that even under DTE's own numbers DTE would not have been able to seek the large rate increases it has sought in its last six general rate cases, and is seeking in this proceeding, but for being permitted to use a projected test year. To put it another way, the use of a projected test year allows DTE to begin recovery of

costs before those costs have been verified as being real and prudently incurred. This has had and continues to have several adverse impacts on customers.

First, it has caused and continues to cause customers to experience rate increases sooner because rates are being based on future projections.

Second, it has resulted in higher rates for customers than if rates were based on the historical test year.

Third, it has allowed and continues to allow DTE to fill its projections with proposed capital expenditures and expenses that either DTE has not irrevocably committed to making or otherwise can avoid if it finds it advantageous to do so to improve its realized rate of return for its shareholders. This can allow DTE to collect revenue from its customers for capital expenditures or expenses it does not ultimately incur or has not yet incurred when rates are placed into effect. This unreasonably benefits DTE's shareholders at the expense of DTE's customers.

Finally, the use of a projected test year greatly handicaps the Commission Staff and intervenors in reviewing DTE's rate filings to ensure the projected capital expenditures and expenses are reasonable because they are not actual capital expenditures and expenses reflected on DTE's books, but rather projections developed over many separate cost subaccounts and revenue categories. This requires much more time and greater resources than are necessary in a rate proceeding that utilizes a historical test year all while the rate case timing has been compressed down to a 10-month time frame. As a result, while some inappropriate cost projections by DTE may be identified and successfully disallowed as a result of Commission Staff and intervenor review of DTE's projections, many other inappropriate cost projections may be missed and inappropriately included in DTE's rates at the expense of its customers as I have outlined above.

Q ARE DTE'S PROJECTED BRIDGE PERIOD CAPITAL EXPENDITURES AND FORECASTED TEST YEAR EXPENSES AND CAPITAL EXPENDITURES KNOWN AND MEASURABLE CHANGES TO ITS HISTORICAL TEST YEAR?

A No, they are not. Known and measurable changes are changes to costs that are inescapable and precisely identifiable in amount and timing. Future capital expenditures and projected expenses are often not inescapable, not precisely identifiable in amount and timing, or both. When they are escapable or not precisely identifiable with respect to amount and timing, they are not known and measurable changes from the historical test year. Furthermore, many of the capital expenditures and expenses that DTE has attempted to recover in past general rate cases and is attempting to recover in this current proceeding, as shown by the direct testimony of my colleague, Ms. York, are highly speculative. These include capital expenditures and expenses that DTE has not irrevocably committed to make. These too are not known and measurable changes from the historical test year.

Q PLEASE PROVIDE SOME EXAMPLES OF CHANGES FROM A HISTORICAL TEST YEAR THAT ARE KNOWN AND MEASURABLE CHANGES.

A Examples of valid known and measurable changes to historical test year amounts include:

- Normalization to address the effects of volatility, such as those related to economic conditions or weather, and unusual events such as extended forced generation outages that distort the amounts that fall within the historical test year;

- Annualization to address costs, such as those associated with nuclear generation refueling outages and other types of extended planned generation outages, that regularly occur on a periodic basis, but not in every year;

- Costs that only occurred during the later months of the historical test year and are expected to continue at that same level on a going forward basis; and

- Imminent changes in costs that will occur during the period between the end of the historical test period and the date new base rates go into effect and are expected to continue on a going forward basis.

Q IS THERE ANY EVIDENCE THAT SUGGESTS THAT DTE HAS BEEN OVER COMPENSATED AS A RESULT OF BEING ALLOWED TO USE A PROJECTED TEST YEAR?

A Yes. As my Table JRD-1 shows, in its rate filing in this proceeding and in its two rate filings before it, DTE has consistently reported large revenue sufficiencies for its historical test year that have ranged from $80.5 to $111.7 million. This means that, in each of these historical test years (calendar years 2020, 2021 and 2022), DTE received revenues $80.6 to $111.7 million higher than necessary to earn its authorized rate of return during that historical test year. While COVID-19 may have in part caused the large revenue sufficiencies reported for 2020 and 2021, it does not change the fact that DTE's present rates were ultimately more generous than they needed to be to provide DTE a reasonable opportunity to earn its authorized return.

It is also important to note that the historical test year values presented in my Table JRD-1 are DTE's reported historical test year values. If these historical test year values were closely examined they might very well reveal costs that are not recoverable in rates. As a result, DTE's actual revenues in excess of its authorized rate of return in each of these three historical test years (2020, 2021 and 2022) may very well have been well in excess of the approximately $80.6 to $111.7 million DTE has reported.

The bottom line with respect to these most recent three historical test year results is that, if projected costs for DTE were being properly set in DTE's rate proceedings, about half the time these historical test years would show a revenue sufficiency and about half the time these historical test years would show a revenue

deficiency. However, this is not what is happening. Instead, DTE is consistently being granted rates based on projected costs that are clearly much higher than DTE is subsequently actually incurring such that DTE is consistently earning a windfall of tens of millions of dollars per year. This will not end until the Commission: (i) disallows DTE from using a projected test year for its base rates, (ii) becomes much more aggressive in terms of rejecting DTE's unsupported projections, or (iii) institutes other measures that prevent or greatly limit DTE overearnings that result from DTE's over projections.

Q IS THE COMMISSION REQUIRED TO SET RATES USING A PROJECTED TEST YEAR?

A No. As the Commission discussed in its November 2, 2009 Order in Case No. U-15645, p. 8, Section 6a(1) of Act 286, MCL 460.6a(1), provides that a utility "may use projected costs and revenues for a future consecutive 12-month period" to develop its requested rates and charges. The Commission added that the Staff and intervenors should direct their focus "upon the strengths and weaknesses of the evidentiary presentations of the parties regarding specific expense and revenue projections." In a case where a utility decides to base its filing on a fully projected test year, however, the utility bears the burden to substantiate its projections.[2] Recognizing the statutory time constraints present in a base rate case, the Commission has directed utilities to include all evidence (or sources of evidence) in support of their test year projections in their initial rate case filings.[3] If the utility cannot or will not provide sufficient support for a particular revenue or expense item (particularly for an item that substantially deviates from the historical data), "the Commission may choose an alternative method for

[2] *In re Detroit Edison Application for Rate Increase*, MPSC Case No. U-15768, January 11, 2010 Order, p 9.
[3] *Id*.

determining the projection."[4] That alternative method should be the use of the historical test year amount for that item adjusted for only known and measurable changes to the amount for that item.

Q WHAT DO YOU RECOMMEND TO THE COMMISSION WITH RESPECT TO THIS ISSUE?

A Given DTE's track record with respect to its use of a projected test year causing it to be greatly overcompensated by its customers, my primary recommendation is that the Commission send a strong signal to DTE that DTE's consistent overearning must stop. I propose the Commission do this by outright rejecting DTE's proposed use of a projected test year in this proceeding rather than trying to flushout all of DTE's poorly supported cost projections – an approach that is clearly not sufficiently working given DTE's record of three years of large historical test year revenue sufficiencies. This would appropriately reject DTE's request for a rate increase in this proceeding in its entirety given DTE is showing a $80.5 million revenue sufficiency in its proposed historic test year in this proceeding.

Q IF, DESPITE YOUR RECOMMENDATION, THE COMMISSION ALLOWS DTE TO USE A PROJECTED TEST YEAR IN THIS PROCEEDING, WHAT DO YOU INSTEAD RECOMMEND TO THE COMMISSION?

A If, despite my recommendation, the Commission decides to allow DTE to use a projected test year for this proceeding, which it should not, I have a near-term recommendation and a one long-term recommendation, discussed further below, that the Commission should instead adopt.

[4] *Id.*

First, I recommend the Commission, be much more vigilant and aggressive with respect to ensuring the expenses and investments being projected by DTE for its projected test year are truly expenses and investments that are necessary to provide reliable electric service at lowest reasonable cost. The Commission should also ensure that DTE is irrevocably committed to incur its projected expenses and investments or otherwise cannot avoid them. Finally, the Commission should ensure that DTE's projected investments and expenses are precisely quantified by DTE with respect to both amount and the specific quarter in which DTE will incur these investments and expenses. As I have noted, it is clear from the recent track record of DTE reporting historical test year revenues $80.5 to $111.7 million in excess of its authorized return in its three most recent general rate proceedings (the current one and Case Nos. U-20836 and U-21297) [5] that it is likely to some extent either questionable projections of DTE are not being caught by intervenors and/or Staff in their review of DTE's proposals given the complexity of verifying those projections, the Commission has provided too great of a benefit of doubt to DTE with respect to the costs found to be questionable by intervenors and/or Staff, DTE is not actually incurring the costs it has projected, or some combination of the three has been occurring. DTE will essentially continue to earn a rate of return higher than authorized by the Commission unless and until this issue is brought under control. However, given DTE's consistent very large revenue sufficiencies for its three most recent historical test year, ABATE has no confidence, without major reform with respect to the use of projected test years, which the Commission will be generically exploring as part of Case No. U-21637, that the Commission will be able to sufficiently root out DTE's over-projections of cost in this current proceeding. For this reason, until the Commission can in Case No. U-21637

[5]Table JRD-2.

explore other alternatives to reign in DTE's overearning related to its use of a project test year and implement the reforms resulting from that exploration, my primary recommendation is to outright reject DTE's proposed use of a projected test year.

Q WHAT IS YOUR LONGER TERM RECOMMENDATION TO THE COMMISSION?

A ABATE recommended in its May 14, 2021 and August 11, 2021 filed comments in Case No. U-18238 that, as part of reconvening a collaborative work group to discuss the experience and impact of the rate case filing requirements set forth in its July 31, 2017 order in Case No. U-18238, the Commission have the collaborative workgroup address the use of projected test years and utility ROE requests continuing to result in excess revenue collection from customers under the Commission's current minimum filing requirements.[6] As detailed in its May 14, 2021 Comments, the Commission should examine: (i) customer benefits and detriments that have resulted from the use of projected test years; (ii) conditions under which the Commission would reject the use of a projected test year; (iii) categories of expenses/revenues that are uniquely difficult to predict so as to render their inclusion in a projected test year inappropriate; (iv) minimum criteria to reasonably demonstrate a sufficient commitment by the utility to actually incur the expenses it projects; (v) length of time between the end of the historical test year and the beginning of the proposed projected test year; (vi) a method of tracking projections for various costs to determine consistency and extent of over- or under-projection and potential projection guardrails or limits; and (vii) whether the use of a projected test year by a utility should factor into its authorized ROE. Further attention to these issues could help tailor and bolster the Filing Requirements and utility

[6]U-18238, ABATE May 14, 2021 Comments at 1.

rate case applications to ensure that projected test year filings more accurately and reasonably align projections with utility revenue requirements.[7]

While the Commission's August 11, 2022 order in Case No. U-18238 did not adopt ABATE's recommendation, the Commission has recently opened a new proceeding in Case No. U-21637 to investigate opportunities for improving the process by which it reviews applications filed under ML 460.6a. In its May 23, 2024 Order in that proceeding, the Commission has posted a number of questions to interested persons for comment, including questions with respect to the continued use of projected test years by the utilities the Commission regulates.

ABATE will be actively participating in this new proceeding and recommends that the Commission fully utilize this new proceeding to examine: (i) customer benefits and detriments that have resulted from the use of projected test years; (ii) conditions under which the Commission would reject the use of a projected test year; (iii) categories of expenses/revenues that are uniquely difficult to predict so as to render their inclusion in a projected test year inappropriate; (iv) minimum criteria to reasonably demonstrate a sufficient commitment by the utility to actually incur the expenses it projects; (v) length of time between the end of the historical test year and the beginning of the proposed projected test year; (vi) a method of tracking projections for various costs to determine consistency and the extent of over- or under-projection and potential projection guardrails or limits; and (vii) whether the use of a projected test year by a utility should factor into its authorized ROE. The fact of the matter is that utility use of projected test years for ratemaking remains broken and will continue to be so until the Commission fully addresses the issues associated with the use of projected test years by the utilities under its jurisdiction.

[7] *Id.* at 5-6.

III. DTE'S Distribution Investment Recovery Mechanism

Q DOES THE COMPANY CURRENTLY HAVE AN IRM?

A Yes. In the Company's last general rate case proceeding, Case No. U-21297, the Commission for the first time authorized an IRM for the Company for certain categories of distribution investments in the amount of approximately $61.9 million for Year 1 (December 1, 2023 through December 31, 2024) and $290.1 million for Year 2 (January 1, 2025 through December 31, 2025).[8] It is important to note the accompanying DTE distribution IRM surcharge only began to apply to customer bills a little over seven months prior to the filing of my direct testimony herein and the Company's first distribution IRM reconciliation proceeding will not commence until sometime in 2025. In addition, it is important to note the Commission in Case No. U-21297 denied the Company's request for a Year 3 (January 1, 2026 through December 31, 2026) for its distribution IRM with an investment of $532.7 million.

Specifically:

> "[T]he Commission finds that approval is limited to Plan Years 1 and 2. As noted on the record, there is ongoing discussion regarding PBR in Case No. U-21400 and an ongoing audit in Case No. U-21305. Therefore, the Commission finds that limiting the approval to the first two years will allow the company to move forward with the IRM without precluding the incorporation of any potential insights gained from those proceedings to better inform the potential continuation of the IRM."[9]

Q WHAT IS THE COMPANY PROPOSING IN THE CURRENT PROCEEDING WITH RESPECT TO ITS DISTRIBUTION IRM?

A The Company proposes to add a Year 3 (calendar year 2026) with $530.0 million of investment and a Year 4 (calendar year 2027) with $720.0 million of investment. In

[8]Case No. U-21297 Final Order at 291.
[9]Case No. U-21297 Final Order at 289.

doing so, the Company proposes to add a new category of investments called "Pole and Pole Top Maintenance and Modernization," which contributes $150 million of the proposed investment in 2026 and $200 million of the proposed investment in 2027.[10] In addition, the Company proposes to broaden the investment category "4.8 kV Circuit Automation" to "Distribution Automation," which increases annual investment in 2026 and 2027 to $105.0 million and $180.0 million, respectively, versus the $24.4 to $26.4 million authorized for Year 1 and Year 2 of its distribution IRM.[11] Finally, while not outright requesting it, the Company indicates it would support expanding its authorized $290.1 million of capital expenditures for Year 2 (calendar year 2025) for its distribution IRM by $434.1 million to $724.1 million by adding four additional areas of capital investment beyond that authorized by the Commission in Case No. U-21297.[12]

Q HOW DO YOU RESPOND TO DTE'S NEW DISTRIBUTION IRM PROPOSALS?

A DTE's proposals to: (i) add up to $434.1 million of investment to Year 2 of its authorized distribution IRM, (ii) add the new category of investment called "Pole and Pole Tape Maintenance and Modernization," (iii) expand the scope of "4.8 kV Circuit Automation" to "Distribution Automation" and (iv) the add a Year 4 to its authorized distribution IRM should all be rejected. The Commission at this time should only permit DTE to add a Year 3 to its distribution IRM and only for the existing authorized categories of "Conversion," "Subtransmission Redesign and Rebuild," "Breaker Replacement" and "URD Replacement" for a total investment amount for Year 3 of $275.0 million.

I make this recommendation for the following reasons:

- DTE's distribution IRM should not at this time be dramatically expanded and extended as proposed by DTE given DTE's distribution IRM is still in its infancy. Year 1 just barely commenced seven months prior to the filing of this testimony and

[10]DTE witness Foley Direct at NTF-8 to NTF-9.
[11]DTE witness Foley Direct at NTF-8 to NTF-9.
[12]DTE witness Foley Direct at NTF-18.

the first DTE distribution IRM reconciliation will not commence until sometime in 2025; and

- The term of the authorized distribution IRM for DTE should at this time be limited to no longer than truly necessary, as the Commission concluded in its Final Order in Case No. U-21297, until potential insights from Case Nos. U-21400 and U-21305 are gained to better inform continuation of the distribution IRM.

This said, to address DTE's concern with respect to a temporary stopping and starting of its distribution IRM[13] and to potentially reduce the likelihood DTE would file a rate case in 2025 for the sole purpose of adding a Year 3 to its distribution IRM, I do not oppose the Commission at this time adding a Year 3 to DTE's distribution IRM for the existing investment categories of "Conversions," "Subtransmission Redesign and Rebuild," "Breaker Replacement" and "URD Replacement" in the amounts proposed by DTE in this proceeding for Year 3, which total to $275.0 million. This would at this time only authorize one additional year for the distribution IRM and only do so for a level of investment similar to that already authorized for Year 2 ($290.1 million).

Q DTE ARGUES A YEAR 4 NEEDS TO BE AUTHORIZED AT THIS TIME TO AVOID A LAPSE IN THE IRM AND PROVIDE GREATER CERTAINTY WITH RESPECT TO ITS FUTURE USE.[14] HOW DO YOU RESPOND?

A The risk of a temporary lapse in the distribution IRM is sufficiently addressed by adding a Year 3 in the limited manner I have recommended. With respect to longer term future use of the IRM, granting a Year 4 would essentially presume a long-term future that has not yet been determined by the Commission. As I have recommended, the request for the authorization of a Year 4 for DTE's distribution IRM should at this time be rejected.

[13]DTE witness Foley Direct Testimony at 16.
[14]DTE witness Foley Direct at NTF-16.

IV. DTE Rider 10: MISO Locational Marginal Price ("LMP")

Q CAN YOU PLEASE BRIEFLY DESCRIBE DTE RIDER 10?

A DTE Rider 10 ("R10") is a large customer interruptible service rate under which the load is designated as a planning resource under the MISO Resource Adequacy Construct and a significant portion of the customer's power supply rates involve a pass-through of the MISO real-time hourly Locational Marginal Price ("LMP") for energy.[15]

Q WHAT IS YOUR CONCERN WITH RESPECT TO R10 IN THIS CURRENT PROCEEDING?

A ABATE members utilizing R10 would like to have the option, on an annual basis, of selecting the use of the applicable day-ahead LMP rather than the applicable real-time LMP. The reason for this is twofold. First, provided a customer provides a day-ahead estimate of hourly demand to DTE and DTE submits it into the MISO day-ahead market, the vast majority of the energy for the customer will be obtained by DTE from MISO at the hourly day-ahead LMP rather than the hourly real-time LMP. Second, the day-ahead LMP is known before real-time such that a customer using it would in advance have a price signal with respect to the impact on its bill of increasing or decreasing its energy consumption in real-time.

Q IS THE REAL-TIME LMP REASONABLY PREDICTABLE IN ADVANCE?

A On average, it is based on day-ahead LMP values, but it is not so on an hour-to-hour basis. As a result, selection of the day-ahead LMP by a R10 customer would provide it a much more predictable price signal.

[15]DTE Electric Company, Electric Tariff at D-91.00.

Q WHY WOULD IT BE AN ANNUAL ELECTION?

A It would be an annual election to ensure no customer tries to game moving back and forth between day-ahead and real-time LMPs on an hour-to-hour or day-to-day basis. Instead, customers must live with their selection for an entire year at a time.

Q ARE YOU AWARE OF OTHER UTILITY TARIFF RATES SIMILAR TO DTE R10 THAT USE THE DAY-AHEAD RATHER THAN REAL-TIME LMP?

A Yes. Northern Indiana Public Service Company ("NIPSCO") Rate 531 under Tier 2 service, which has a number of similarities to DTE R10, uses the day-ahead LMP rather than the real-time LMP. I have attached a copy of NIPSCO Rate 531 as Exhibit AB-3 to this testimony. Rate 531 Tier 2 service is described on pages 2 and 3 of the exhibit.

Q WHAT DO YOU RECOMMEND?

A I recommend the Commission require DTE to modify its R10 tariff to allow all R10 customers on an annual basis to choose between the applicable day-ahead LMP or the applicable real-time LMP.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of James R. Dauphinais

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James R. Dauphinais. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017, USA.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I graduated from Hartford State Technical College in 1983 with an Associate's Degree in Electrical Engineering Technology. Subsequent to graduation, I was employed by the Transmission Planning Department of the Northeast Utilities Service Company[1] as an Engineering Technician.

While employed as an Engineering Technician, I completed undergraduate studies at the University of Hartford. I graduated in 1990 with a Bachelor's Degree in Electrical Engineering. Subsequent to graduation, I was promoted to the position of Associate Engineer. Between 1993 and 1994, I completed graduate level courses in the study of power system analysis, power system transients and power system protection through the Engineering Outreach Program of the University of Idaho. By 1996 I had been promoted to the position of Senior Engineer.

[1] In 2015, Northeast Utilities changed its name to Eversource Energy.

In the employment of the Northeast Utilities Service Company, I was responsible for conducting thermal, voltage and stability analyses of the Northeast Utilities' transmission system to support planning and operating decisions. This involved the use of load flow, power system stability and production cost computer simulations. It also involved examination of potential solutions to operational and planning problems including, but not limited to, transmission line solutions and the routes that might be utilized by such transmission line solutions. Among the most notable achievements I had in this area include the solution of a transient stability problem near Millstone Nuclear Power Station, and the solution of a small signal (or dynamic) stability problem near Seabrook Nuclear Power Station. In 1993 I was awarded the Chairman's Award, Northeast Utilities' highest employee award, for my work involving stability analysis in the vicinity of Millstone Nuclear Power Station.

From 1990 to 1996, I represented Northeast Utilities on the New England Power Pool Stability Task Force. I also represented Northeast Utilities on several other technical working groups within the New England Power Pool ("NEPOOL") and the Northeast Power Coordinating Council ("NPCC"), including the 1992-1996 New York-New England Transmission Working Group, the Southeastern Massachusetts/Rhode Island Transmission Working Group, the NPCC CPSS-2 Working Group on Extreme Disturbances and the NPCC SS-38 Working Group on Interarea Dynamic Analysis. This latter working group also included participation from a number of ECAR, PJM and VACAR utilities.

From 1990 to 1995, I also acted as an internal consultant to the Nuclear Electrical Engineering Department of Northeast Utilities. This included interactions with the electrical engineering personnel of the Connecticut Yankee, Millstone and

Seabrook nuclear generation stations and inspectors from the Nuclear Regulatory Commission (“NRC”).

In addition to my technical responsibilities, from 1995 to 1997, I was also responsible for oversight of the day-to-day administration of Northeast Utilities' Open Access Transmission Tariff. This included the creation of Northeast Utilities' pre-FERC Order No. 889 transmission electronic bulletin board and the coordination of Northeast Utilities' transmission tariff filings prior to and after the issuance of Federal Energy Regulatory Commission (“FERC” or “Commission”) FERC Order No. 888. I was also responsible for spearheading the implementation of Northeast Utilities' Open Access Same-Time Information System and Northeast Utilities’ Standard of Conduct under FERC Order No. 889. During this time, I represented Northeast Utilities on the Federal Energy Regulatory Commission's "What" Working Group on Real-Time Information Networks. Later I served as Vice Chairman of the NEPOOL OASIS Working Group and Co-Chair of the Joint Transmission Services Information Network Functional Process Committee. I also served for a brief time on the Electric Power Research Institute facilitated "How" Working Group on OASIS and the North American Electric Reliability Council facilitated Commercial Practices Working Group.

In 1997 I joined the firm of Brubaker & Associates, Inc. The firm includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science and business. Since my employment with the firm, I have filed or presented testimony before the Federal Energy Regulatory Commission in Consumers Energy Company, Docket No. OA96-77-000; Midwest Independent Transmission System Operator, Inc., Docket No. ER98-1438-000; Montana Power Company, Docket No. ER98-2382-000; Inquiry Concerning the Commission’s Policy on Independent System Operators, Docket No. PL98-5-003; SkyGen Energy LLC v. Southern

Company Services, Inc., Docket No. EL00-77-000; Alliance Companies, et al., Docket No. EL02-65-000, et al.; Entergy Services, Inc., Docket No. ER01-2201-000; Remedying Undue Discrimination through Open Access Transmission Service, Standard Electricity Market Design, Docket No. RM01-12-000; Midwest Independent Transmission System Operator, Inc., Docket No. ER10-1791-000; NorthWestern Corporation, Docket No. ER10-1138-001, et al.; Illinois Industrial Energy Consumers v. Midcontinent Independent System Operator, Inc., Docket No. EL15-82-000; Midcontinent Independent System Operator, Inc., Docket No. ER16-833-000; Midcontinent Independent System Operator, Inc., Docket No. ER17-284-000; and Midcontinent Independent System Operator, Inc. and Ameren Services Company Docket No. ER18-463-000. I have also filed or presented testimony before the Alberta Utilities Commission, the California Public Utilities Commission, the Colorado Public Utilities Commission, the Connecticut Department of Public Utility Control, the Florida Public Service Commission, the Idaho Public Service Commission, the Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Iowa Utilities Board, the Kentucky Public Service Commission, the Louisiana Public Service Commission, the Michigan Public Service Commission, the Missouri Public Service Commission, the Montana Public Service Commission, the Nevada Public Utilities Commission, the New Mexico Public Regulation Commission, the Council of the City of New Orleans, the Oklahoma Corporation Commission, the Public Utility Commission of Texas, the Virginia State Corporation Commission, the Wisconsin Public Service Commission, the Wyoming Public Service Commission, Federal District Court and various committees of the Illinois, Missouri and South Carolina state legislatures. This testimony has been given regarding a wide variety of issues including, but not limited to, ancillary service rates, avoided cost calculations, certification of public convenience

and necessity, class cost of service, cost allocation, fuel adjustment clauses, fuel costs, generation interconnection, interruptible rates, market power, market structure, off-system sales, prudency, purchased power costs, resource adequacy, resource planning, rate design, retail open access, standby rates, transmission losses, transmission planning, transmission rates and transmission line routing.

I have also participated on behalf of clients in the Southwest Power Pool Congestion Management System Working Group, the Alliance Market Development Advisory Group and several committees and working groups of the Midcontinent Independent System Operator, Inc. ("MISO"), including the Congestion Management Working Group; Economic Planning Users Group; Loss of Load Expectation Working Group; Market Subcommittee; Michigan Transmission Studies Task Force; Planning Subcommittee; Regional Expansion, Criteria and Benefits Working Group; Resource Adequacy Subcommittee (formerly the Supply Adequacy Working Group); and Reliability Subcomittee. I am currently a member of the MISO Advisory Committee in the end-use customer sector on behalf of industrial customer groups in Illinois, Louisiana, Michigan and Texas. I am also the past Chairman of the Issues/Solutions Subgroup of the MISO Revenue Sufficiency Guarantee ("RSG") Task Force.

In 2009, I completed the University of Wisconsin-Madison High Voltage Direct Current ("HVDC") Transmission course for Planners that was sponsored by MISO. I am a member of the Power and Energy Society ("PES") of the Institute of Electrical and Electronics Engineers ("IEEE").

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky; and Phoenix, Arizona.

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**

Rebuttal Testimony and Exhibits of

James R. Dauphinais

On behalf of

Association of Businesses Advocating Tariff Equity

August 16, 2024

BRUBAKER & ASSOCIATES, INC.

Project 11638

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**

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STATE OF MICHIGAN
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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**

Rebuttal Testimony of James R. Dauphinais

I. Introduction

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James R. Dauphinais. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q ARE YOU THE SAME JAMES R. DAUPHINAIS WHO PREVIOUSLY FILED DIRECT TESTIMONY ON JULY 26, 2024 ON BEHALF OF ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY ("ABATE")?

A Yes, I am.

Q WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A My rebuttal testimony addresses the Direct Testimony of Citizens Utility Board of Michigan ("CUB"), Sierra Club ("SC"), Michigan Environmental Council ("MEC"), and Natural Resources Defense Council ("NRDC") (collectively, "MNSC") witness Douglas B. Jester with respect to his proposal to change the demand portion of the current DTE Electric Company ("DTE" or "Company") 4-CP 75-0-25 production facility cost allocator

used in DTE's Class Cost of Service ("CCOS") Study from being based on customer class demand at the time of DTE's four summer monthly system peaks (June, July, August and September) (i.e., summer four coincident peak ("4-CP") demand) to being based on what he refers to as a "weighted incremental share of production plant by season" method, or, in the alternative, a 9-CP demand method that uses the class monthly coincident peak demands of March through November.[1] I also address MNSC witness Jester's related rate design proposal with respect to the recovery in rates of the production facility costs allocated to each customer class.[2] Finally, I briefly address his proposal to change DTE's distribution rate design to be based on seasonal distribution capacity utilization.[3]

In addition, I address the Direct Testimony of Michigan Energy Innovation Business Council ("Michigan EIBC"), Institute for Energy Innovation ("IEI") and Advanced Energy United ("United") (collectively, "MEIU") witness Dr. Laura S. Sherman with respect to her proposal to require DTE to account for societal benefits, including greenhouse gas and criteria pollutant emissions reductions, in its benefit to cost analysis for its Transportation Electrification Plan ("TEP").[4]

My silence with regard to any issue should not be construed as an endorsement of the position of any party on that issue in this proceeding.

Q PLEASE BRIEFLY SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS IN THIS PROCEEDING.

A My rebuttal testimony conclusions and recommendations are as follows:

- MNSC witness Jester's proposal to modify the demand portion of DTE's current 4-CP 75-0-25 production facility allocator to use either a "weighted incremental share

[1]Jester Direct at 12-20 and 44.
[2]Jester Direct at 21-23 and 44.
[3]Jester Direct at 23 and 44.
[4]Sherman Direct at 24-36 and 64.

of production plant by season" method or, alternatively, a 9-CP method, rather than the current 4-CP method, is not reasonable for the following reasons:

- MNSC witness Jester, with respect to MISO's capacity credit requirements, only considered the MISO-wide requirement. He failed to consider the MISO Local Clearing Requirement ("LCR") for MISO Local Resource Zone ("LRZ" or "Zone") 7, the Zone DTE is located within, and how DTE's peak system demand, not DTE's demand at the time of the MISO-wide system peak, drives that need.

- MNSC did not update the system peak demand test analyses that were performed in Case No. U-17689 by DTE and ABATE and were the basis of the Commission's adoption of the 4-CP method in that proceeding. As I present in my testimony herein, when those analyses are updated, they show an even stronger case for the use of 4-CP for DTE than they did in Case No. U-17689.

- Even if DTE's MISO-wide capacity credit requirement for each season were alone used to determine the appropriate demand allocation for production facility costs, which as I have noted should not be done, that information at best potentially supports the use of a summer 5-CP (May, June, July, August and September) demand allocation, not a March through November 9-CP allocation or MNSC witness Jester's "weighted incremental share of production plant by season" method.

- For the foregoing reasons, MNSC witness Jester's proposal in this proceeding with respect to changing the demand portion of DTE's production plant cost allocator from a 4-CP method should be rejected and the current 4-CP method should continue to be used.

- In addition, given his production facility cost rate design proposal was contingent on Commission adoption of one of his proposed changes to the demand portion of DTE's production plant cost allocator, that proposal should be rejected as well.

- With respect to MNSC witness Jester's proposal to have the Commission require DTE in its next rate case to file a distribution rate design based on seasonal utilization, ABATE cautions that utilization and cost causation are not necessarily always in alignment. As such, while ABATE does not object to MNSC's purely informational request for the next rate case filing by DTE, ABATE reserves the right to respond to any proposals in future DTE rate proceedings for DTE to actually adopt a distribution class cost of cost service method or distribution rate design based on seasonal utilization.

- With respect to MEIU witness Sherman's proposal for the Commission to require DTE to account for societal benefits, including greenhouse gas and criteria pollutant emissions reductions, in its benefit to cost analysis for its TEP, while ABATE would not object to the use of the Societal Cost Test ("SCT") or societal benefits for informational purposes as a sensitivity case, the Commission should not require DTE use the SCT, or any other inclusion of societal benefits, including greenhouse gas and criteria pollutant emissions, in DTE's base case BCA for its TEP. In addition, DTE's TEP should not be expanded on the basis of societal benefits associated with avoided transportation emissions, as that would amount to

mandating electric ratepayers subsidize the cost of providing the claimed societal benefits and is likely be beyond the authority of the Commission to require.

II. Response to MNSC Production Facility Cost Allocation and Rate Design Proposals

A. Background on the Current 4-CP 75-0-25 Production Facility Cost Allocator

Q PLEASE BRIEFLY DESCRIBE DTE'S CURRENT 4-CP 75-0-25 PRODUCTION FACILITY COST ALLOCATOR AND HOW THE DEMAND PORTION OF THAT ALLOCATOR CAME TO BE BASED ON 4-CP DEMAND.

A The 4-CP 75-0-25 production facility cost allocator is used in DTE's CCOS Study to allocate production facility costs to customer classes. Production facility costs (or fixed production costs) are the costs associated with the recovery of the capital expenditures for DTE's generation facilities -- specifically, the cost of capital, depreciation expense and taxes associated with those capital expenditures. DTE's production facility costs do not include the fuel or non-fuel O&M costs of DTE's generation facilities. They also do not include DTE's purchased power expenses. However, DTE's capacity-related purchased power expenses recovered through base rates are currently separately allocated to customer classes using a 4-CP 100-0-0 allocator that uses the same 4-CP method as DTE's 4-CP 75-0-25 production facility cost allocator.

Under the 4-CP 75-0-25 production facility cost allocator, which has been used by DTE since the Commission's Final Order in Case No. U-17689 in 2015, 75% of production facility costs are allocated based on the demand of each customer class at the time of DTE's four summer monthly peaks (June, July, August and September) (i.e., summer 4-CP demand) and 25% of production facility costs are allocated based on the annual energy consumption of each customer class.

Use of the 4-CP method for the demand allocation portion of the overall 4-CP 75-0-25 allocator was proposed and supported by DTE and ABATE in the direct testimony they each provided in Case No. U-17689. That testimony included a review of system demand tests that showed DTE is a summer peaking utility and that DTE's production facilities costs should be allocated to customer classes using four summer coincident peaks (June, July, August and September) for the demand allocation portion of the overall production facility cost allocator.[5] The Commission Staff ("Staff') in Case No. U-17689 concurred with this conclusion.[6] The Commission found the following:

> "The Commission agrees with DTE Electric, the Staff, and ABATE, that a change from a 12CP to a 4CP demand allocator is fully supported by the evidence presented in this proceeding. Martin L. Heiser, Consultant, Regulatory Economics for DTE Energy Corporate Services, LLC, explained that the company applied four system demand tests that have been used by the Federal Energy Regulatory Commission to determine the appropriate demand portion of the allocator. The results of these tests are consistent with the results for other utilities for which FERC has authorized a 4CP allocator. *See*, 2 Tr 234-236; Exhibit A-14. The Commission therefore rejects the ALJ's recommendation to retain the 12CP demand allocator."[7]

Q PLEASE EXPLAIN THE BASIS OF ALLOCATING PRODUCTION FACILITY COSTS BASED ON CUSTOMER CLASS DEMAND COINCIDENT WITH THE TIME OF A UTILITY'S SYSTEM PEAK.

A The total amount of production facility capacity a utility needs is directly dependent on the total demand of its load at the time of its annual system peak. Furthermore, it is solely dependent upon this if the capacity the utility acquires to reliably meet its annual system peak is alone sufficient to reliably serve the utility's load for the balance of the year, including during periods of scheduled production facility maintenance outages.

[5]Case No. U-17689, Final Order, June 15, 2015 at 3-5.
[6]*Id.* at 5.
[7]*Id.* at 20.

The higher the demand of a customer class at the time of the utility's system peak, the more that customer class contributes to the utility's total demand at the utility's system peak and, thus, the utility's total need for production facility capacity. Hence, it is appropriate to allocate production facility costs to customer classes based on the demand of the customer class at the time of (i.e. coincident with) the utility' system peak.

Q PLEASE EXPLAIN WHY MORE THAN ONE COINCIDENT PEAK IS SOMETIMES USED.

A When only customer class demand at the time of the annual system peak for the utility is utilized for allocating production facility costs, the method is typically referred to as a 1-CP method. The 1-CP method is an appropriate method when the utility's demand at its annual system peak is significantly higher than its demand at the time of its system peaks in other months such that the utility's load can be reliably served throughout the rest of the year without additional production facility capacity while accommodating scheduled maintenance outages for the utility's fleet of production facilities.

However, when the time of the utility's annual system peak moves around between a few adjacent months such that those monthly system peaks on average over several years are very close in magnitude, it may be more appropriate to allocate production facility costs to customer classes based on demand of each customer class at the time of the system peak of the utility in each of those months. This is what was found to be the case for DTE through the system peak tests DTE and ABATE presented in their respective direct testimonies in Case No. U-17689. Specifically, as I have noted, both DTE and ABATE found from the application of system demand tests that the demand allocation for DTE's production facility costs should be based on customer

class demand at the time of DTE's monthly system peaks during the summer months of June, July, August and September.

Q PLEASE EXPLAIN HOW THE NUMBER OF MONTHLY COINCIDENT PEAKS UTILIZED IS DETERMINED FROM SYSTEM PEAK TESTS SUCH AS THOSE THAT WERE PERFORMED BY DTE AND ABATE IN CASE NO. U-17689.

A The appropriate number of monthly coincident peaks to utilize for allocation is typically determined by performing what are referred to as system peaks tests over several years of historical data. This is what DTE and ABATE did in their testimony in Case No. U-17689.

DTE witness Heiser, in his direct testimony in Case No. U-17689, used a method under which the utility's demand at each of its monthly system peaks over several years is run through four tests that are based on past Federal Energy Regulatory Commission ("FERC") precedent with respect to awarding specific numbers of CPs to various utilities for production facility cost allocation in wholesale electric service ratemaking. Mr. Heiser used six years of DTE historical data, for 2008 through 2013, from FERC Form 1 and compared the use of 1-CP, 3-CP, 4-CP and 12-CP. From his analysis, he arrived at the conclusion that the results of the tests for DTE using the six years of historical data he examined were consistent with those of other utilities for which FERC has allowed the 4-CP method of allocating production facility costs.[8] Specifically, his results showed use of 4-CP demand for DTE passed all four of the system demand tests he utilized that are based on FERC precedent.[9]

In Case No. U-17689 ABATE witness Selecky used a method in which he utilized ten years, rather than six years, of DTE historical data, for 2004 through 2013,

[8]Case No. U-17689 at 2 Tr 234-236 and Exhibit A-14.
[9]*Id.*

from FERC Form 1 and then calculated DTE's average system peak demand for each month over that ten-year period. He found July had the highest average system peak demand and the average system peak demands for June, August and September were, respectively, 94%, 98% and 87% of the July value. He also found that DTE's average system peak demand in all other months was 76% or lower than that for July. He concluded these results support the use of no more than 4-CP (June, July, August and September) demand for DTE and that a case could be made from them for the use of 3-CP demand instead of 4-CP demand given the drop off from the 94% of the July result for June to the 87% of the July result for September.[10]

Q AT THE TIME OF CASE NO. U-17689, WAS DTE A MEMBER OF THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC. ("MISO") AND WAS THIS CONSIDERED BY EITHER MR. HEISER OR MR. SELECKY?

A DTE was a member of MISO at the time of Case No. U-17689 and Mr. Selecky addressed the relevance of this in his direct testimony in that proceeding. He noted DTE was subject to MISO's resource adequacy requirements that impose a capacity requirement on DTE based on DTE's forecasted system demand at the time of MISO's annual system peak -- a 1-CP allocation method. Mr. Selecky also noted that MISO's annual system peak in the most recent past five years had consistently occurred in summer months, specifically June and July. This further supported the use of no more than 4-CP (June, July, August and September) as the demand allocation for production facility costs for DTE.[11] In addition, it should be noted that MISO then, and today, defines it summer season as consisting only of the calendar months of June, July and August. It does not include September. As a result, this was further evidence that a

[10]Case No. U-17689 at 3 Tr 476 and Exhibit AB-1.
[11]Case No. U-17689 at 3 Tr 476-477.

case at the time could have been made to use a 3-CP demand allocator for DTE rather than a 4-CP demand allocator for DTE. Hence, the selection of the 4-CP allocator at the time was conservative.

B. MNSC Witness Jester's Proposed Modifications to the Current 4-CP 75-0-25 Production Facility Cost Allocator and Associated Rate Design

Q PLEASE BRIEFLY SUMMARIZE MNSC WITNESS JESTER'S PROPOSAL IN THIS CURRENT PROCEEDING WITH RESPECT TO DTE'S PRODUCTION PLANT COST ALLOCATOR AND RATE DESIGN ASSOCIATED WITH THE RECOVERY OF THOSE COSTS FORM CUSTOMER CLASSES.

A MNSC witness Jester proposes to change the current summer four month coincident peak ("Summer 4-CP") demand method used for the demand allocated portion of fixed production costs to either what he refers to as a "weighted incremental share of production plant by season" method, or, in the alternative, a nine month coincident Peak ("9-CP") demand method that includes the monthly coincident peaks of March through November.[12] He justifies his proposal on the basis of MISO's June 2023 move from an annual to seasonal resource adequacy construct, MISO's definition of seasons, and the utilization by DTE's load in each season of the seasonal capacity credits (specifically, MISO Zonal Resource Credits ("ZRCs")) DTE has from its production facilities, purchased capacity and other sources.[13]

In addition, if the Commission accepts either of his proposed modifications to DTE's current 4-CP 75-0-25 production facility cost allocator, MNSC witness Jester proposes DTE's rate design for the recovery of demand allocated production facility

[12]Jester Direct at 18-20 and 44.
[13]Jester Direct at 14-18.

costs through capacity charges be modified to essentially mimic his proposed cost allocation of those costs to customer classes.[14]

Q IS MNSC WITNESS JESTER'S PROPOSAL WITH RESPECT TO MODIFYING THE DEMAND PORTION OF DTE'S CURRENT 4-CP 75-0-25 PRODUCTION PLANT COST ALLOCATOR REASONABLE?

A MNSC witness Jester's proposal to modify the demand portion of DTE's current 4-CP 75-0-25 production facility allocator to use either a "weighted incremental share of production plant by season" method or, alternatively, a 9-CP method, rather than the current 4-CP method, is not reasonable and, as a result, should be rejected by the Commission. The proposal is not reasonable for the following reasons:

- MNSC witness Jester, with respect to MISO's capacity credit requirements, only considered the MISO-wide requirement. He failed to consider the MISO Local Clearing Requirement ("LCR") for MISO Local Resource Zone ("LRZ" or "Zone") 7, the Zone DTE is located within, and how DTE's peak system demand, not DTE's demand at the time of the MISO system peak, drives that need.

- MNSC did not update the system peak demand test analyses that were performed in Case No. U-17689 by DTE and ABATE and were the basis of the Commission's adoption of the 4-CP method in that proceeding. As I present later in this testimony, when those analyses are updated, they show an even stronger case for the use of 4-CP for DTE than they did in Case No. U-17689.

- Even if DTE's MISO-wide capacity credit requirement for each season was alone used to determine the appropriate demand allocation for production facility costs, which as I have noted should not be done, that information at best potentially supports the use of a summer 5-CP (May, June, July, August and September) demand allocation, not a March through November 9-CP allocation or MNSC witness Jester's "weighted incremental share of production plant by season" method.

For these reasons, MNSC witness Jester's proposal in this proceeding with respect to changing the demand portion DTE's production plant cost allocator from a 4-CP method should be rejected and the current 4-CP method should continue to be

[14]Jester Direct at 21-23 and 44.

used. Given his production facility cost rate design proposal was contingent on Commission adoption of one of his proposed changes to the demand portion of DTE's production plant cost allocator, that proposal should be rejected as well.

Q PLEASE EXPLAIN THE MISO LCR AND WHY MNSC WITNESS JESTER'S FAILURE TO CONSIDER IT IS UNREASONABLE.

A MISO's resource adequacy requirements require that both a Zone's share of its MISO-wide capacity requirement, the Zone's Planning Reserve Margin Requirement ("PRMR"), be met and the Zone's LCR be met.[15] If the LCR is not met for a Zone for a particular season, it causes the Zone's loss of load probability to exceed MISO's annual target of no more than one loss of load event day in ten years and causes MISO to set the daily Auction Clearing Price ("ACP") for that season to an amount potentially as high as four times the MISO annual daily gross Cost of New Entry ("CONE") price.[16] For Zone 7, the MISO Zone in which DTE's load is located, for the MISO 2024/2025 Planning Year, this would have been four times $348.32 per MW-day, or $1,393.28 per MW-day.[17]

Given the foregoing consequences, the LCR cannot be ignored when considering the appropriate allocation of production facility costs as MNSC witness Jester did in his direct testimony. This is particularly important for MISO Zone 7 because the Zone 7 LCR typically makes up a very large percentage of the Zone 7 PRMR. For example, for Zone 7 for the MISO 2024/2025 Planning Year, the MISO Summer LCR is approximately 89% of the MISO Summer PRMR, the MISO Fall LCR

[15]MISO Tariff, Module E-1 at Sections 68 and 69A.
[16]MISO Tariff, Module E-1, Sections 69A.7.1 a. and x.
[17]MISO Presentation "Planning Resource Auction Results for Planning Year 2024/2025, April 25, 2024 (https://cdn.misoenergy.org/2024%20PRA%20Results%20Posting%20202404256326 65.pdf) at Slide 26.

is approximately 98% of the MISO Fall PRMR, the MISO Winter LCR is approximately 101% of the Winter PRMR, and the MISO Spring LCR is approximately 83% of the Spring PRMR.[18] Production facility capacity located within Zone 7 can simultaneously meet both the Zone 7 LCR and the Zone 7 PRMR. However, production facility capacity located outside of Zone 7 can only be used to meet the Zone 7 PRMR -- it cannot be used to meet the Zone 7 LCR.

In addition, the LCR for a Zone is directly dependent on the Local Reliability Requirement ("LRR") for the Zone, which is determined by multiplying a LRR ratio (determined by MISO in its annual Loss of Load Expectation Study) by the forecasted peak system demand of the Zone, not the forecasted demand of the Zone at the time of MISO's peak system demand.[19] As a result, the LCR for a Zone is not driven by MISO-wide system peaks, but instead the peak system demand of the Zone, which can be significantly higher than the demand of that Zone at the time of the MISO-wide system peaks. Furthermore, in the case of Zone 7, DTE's system demand is the single largest driver of system demand in the Zone as DTE's system demand makes up approximately 50% of total system demand within Zone 7.[20]

In summary, the LCR of Zone 7 is as important as, if not more important than, the PRMR for Zone 7 and DTE's system demand is the largest single driver of the magnitude of the LCR for Zone 7, not MISO-wide system demand. As a result, the nature of DTE' system peaks is as important of a consideration, if not a more important consideration, with respect to the total amount of production facility capacity DTE needs, as the nature of the MISO-wide capacity requirements. Witness Jester's

[18]MISO Presentation "Planning Resource Auction Results for Planning Year 2024/2025, April 25, 2024 (https://cdn.misoenergy.org/2024%20PRA%20Results%20Posting%20202404256326655.pdf) at Slides 16-19.

[19]MISO Tariff, Module E-1 at Section 69A.5.

[20]DTE's total system demand is the neighborhood of 10,000 MW while the total system demand for Zone 7 is in the neighborhood of 20,000 MW.

approach to basing his recommendation on the MISO-wide capacity credit requirement without considering the Zone 7 LCR therefore fails to accurately reflect the relevant peak system demand.

Q PLEASE EXPLAIN WHY MNSC'S FAILURE TO UPDATE THE SYSTEM PEAK TESTS PERFORMED IN CASE NO. U-17689 IS UNREASONABLE.

A There are two reasons. First, as I have discussed earlier in this testimony, the results of system peak tests performed for, and presented in, Case No. U-17689 were the basis upon which the 4-CP method was proposed by DTE and ABATE and what the Commission cited, in conjunction with the remainder of the record, in approving the use of the 4-CP method by DTE. Second, as I have discussed, the nature of DTE's system peaks is still relevant with respect to determining the allocation of DTE's production facility costs since it is the single largest driver of the Zone 7 LCR.

Q HAVE YOU PERFORMED AN UPDATE OF THE SYSTEM PEAK TESTS ANALYSES THAT WERE PERFORMED IN CASE NO. U-17689?

A Yes, I have downloaded from the FERC website DTE's FERC Form 1 filings and utilized DTE's reported monthly system peak data on page 401b of its FERC Form 1 filings to update the system peak tests performed in Case No. U-17689 by both DTE witness Heiser and ABATE witness Selecky. I have provided the update of DTE witness Heiser's system peaks tests analysis as Exhibit AB-19. I have provided the update of ABATE witness Selecky's system peak tests as Exhibit AB-20.

My update of DTE witness Heiser's analysis uses DTE's monthly system peaks for six years from 2018 through 2023. It shows that all four of the FERC precedent

tests continue to be passed for 4-CP.[21] In addition, the updated analysis shows September has grown in merit with respect to being included in the monthly CPs. Specifically, in DTE witness Heiser's original analysis from Case No. U-17689, five of the DTE annual system peaks occurred in July and one in June.[22] In my update of his analysis, one of the annual peaks occurred in June, two occurred in July, one occurred in August and two occurred in September.[23] Note that none of DTE's annual system peaks occurred during May or during any other month besides the current DTE 4-CP months of June, July, August and September.[24]

My update of ABATE witness Selecky's Case No. U-17689 analysis, which I have provided in Exhibit AB-20, uses DTE's monthly system peaks for the ten years from 2014 through 2023. It also shows that that 4-CP continues to be appropriate for DTE and that September has grown in merit with respect to being included in the monthly CPs. Specifically, in the updated analysis, July remains the highest average monthly peak system demand month and the average monthly system peak demand for June, August and September, as a percentage of July's average peak system demand, are respectively 95%, 98% and 93%.[25] All other months are at 81% or lower.[26] September grew from 87% of July demand in ABATE witness Selecky's original analysis in Case No. U-17689 to 93% of July demand in my update of his analysis -- a six-percentage point increase.[27] While May grew from 76% to 81%, a five-percentage point increase,[28] this is a slower rate of growth than for September and, more

[21]Exhibit AB-19 at page 1, lines 25 through 29.
[22]Case No. U-17689, Exhibit A-14 at page 2, lines 6 through 7.
[23]Exhibit AB-19 at page 2, lines 6 through 9.
[24]Exhibit AB-19 at page 2, lines 1 through 13.
[25]Exhibit AB-20 at lines 6-9.
[26]*Id.* at lines 1 through 5 and lines 10 through 12.
[27]Comparing Exhibit AB-20 at line 9 to Case No. U-17689, Exhibit AB-1 at line 9.
[28]Comparing Exhibit AB-20 at line 5 to Case No. U-17689, Exhibit AB-1 at line 5.

1 importantly, May's 81% of July demand in the updated analysis is still much less than
2 the 95%, 98% and 93% of July demand for June, August and September.

3 **Q YOU INDICATED EARLIER THAT DTE'S SYSTEM DEMAND IS THE LARGEST**
4 **SINGLE DRIVER OF MISO ZONE 7 SYSTEM DEMAND AND, AS A RESULT, DTE'S**
5 **SYSTEM DEMAND IS THE SINGLE LARGEST DRIVER OF THE MISO ZONE 7 LCR**
6 **VALUE. CAN YOU PROVIDE EVIDENCE THAT SUPPORTS THAT THE MISO**
7 **ZONE 7 LCR, JUST LIKE DTE'S SYSTEM DEMAND, EXHIBITS 4-CP**
8 **CHARACTERISTICS?**
9 A Yes. The MISO Zone 7 LCR values for the MISO 2024/2025 Planning Year are 19,271
10 MW for Summer, 19,443 MW for Fall, 17,597 MW for Winter and 16,372 MW for
11 Spring.[29] The MISO Winter and MISO Spring LCR values for Zone 7 are well below
12 the MISO Summer and MISO Fall LCR values. This is consistent with a 4-CP allocation
13 that excludes the six calendar months associated with these two MISO seasons
14 (December, January, February, March, April and May). In addition, as I will discuss
15 further later in this testimony, since January 2016, MISO has been compiling the date
16 and time of the monthly and seasonal MISO-wide and Zonal system peaks. That
17 historical information shows that, to date, the MISO Fall seasonal Zone 7 system peak
18 has always occurred in September, never in October or November. This is also
19 consistent with a 4-CP allocation, as the exclusion of these two additional months
20 (October and November) only leaves the four months: the three MISO Summer months
21 of June, July and August and the one MISO Fall month of September. Hence, the

[29]MISO Presentation "Planning Resource Auction Results for Planning Year 2024/2025, April 25, 2024 (https://cdn.misoenergy.org/2024%20PRA%20Results%20Posting%20202404256326655.pdf) at Slides 16-19.

MISO Zone 7 LCR is driven by the same 4-CP (June, July, August and September) demand that drives DTE's system peaks.

Q YOU HAVE EXPLAINED WHY DTE'S SEASONAL MISO-WIDE CAPACITY CREDIT REQUIREMENTS (I.E, DTE'S SEASONAL PRMR VALUES) SHOULD NOT BE USED ALONE TO DETERMINE THE APPROPRIATE DEMAND ALLOCATION FOR DTE'S PRODUCTION FACILITY COSTS AND THAT THE NATURE OF DTE'S SYSTEM PEAKS SHOULD BE GIVEN SIMILAR OR GREATER WEIGHT. IN ADDITION, YOU HAVE INDICATED THAT, EVEN IF DTE'S SEASONAL PRMR WAS USED ALONE TO DETERMINE THE APPROPRIATE DEMAND ALLOCATION FOR DTE'S PRODUCTION FACILITY COSTS, IT WOULD NOT SUPPORT A MARCH THROUGH NOVEMBER 9-CP DEMAND METHOD OR MNSC WITNESS JESTER'S "WEIGHTED INCREMENTAL SHARE OF PRODUCTION PLANT BY SEASON" METHOD. PLEASE EXPLAIN WHY THIS IS SO.

A MNSC witness Jester developed his recommendation that the Commission adopt either his "weighted incremental share of production plant by season" method, or, alternatively, a 9-CP (March through November) demand method, based on a comparison of DTE's seasonal PRMR (MISO-wide Required ZRCs) to the seasonal ZRCs DTE has available from its production facilities, its purchased capacity and other sources to meet its PRMR (Accredited ZRCs) that he presented on pages 17 and 18 of his direct testimony. In his comparison contained in a confidential table on page 18 of his direct testimony, he calculated the ratio for each MISO season of DTE's Megawatts ("MWs") of PRMR to DTE's MWs of Available ZRCs, which he labeled as DTE's "ZRC utilization percentage." While the table as witness Jester presented it is confidential, the "utilization percentage" values for each season are also identified on

pages 18 and 19 of the public version of his direct testimony. Furthermore, DTE's available ZRCs surplus for each season as a percentage of DTE's PRMR can be derived from the "ZRC utilization percentage" values since it is simply 100% less the inverse of the "ZRC utilization percentage" values. Based on this public information, I have tabulated for each MISO season for the 2024/2025 Planning Year DTE's "ZRC utilization percentage" values and DTE's ZRC surplus values in Table JRD-Rebuttal-1 below.

Table JRD-Rebuttal-1

2024/2025 PY – Comparison of DTE PRMR to DTE Available ZRCs

Description	MISO Summer	MISO Fall	MISO Winter	MISO Spring
DTE ZRC Utilization %	98.4%	98.2%	71.9%	96.5%
DTE's Surplus ZRCs as % of DTE's PRMR	1.6%	1.9%	39.1%	3.6%

Source: Public Jester Direct at 18-19.

Based on the seasonal "DTE ZRC utilization values" presented above, MNSC witness Jester first recommended that a Spring/Summer/Fall 9-CP method be adopted claiming it was "close to the Commission's past practice of allocating Production Plant Demand cost based on the months during which DTE Electric's Production Plant portfolio is most heavily utilized".[30]

He then proceeded to claim that the 9-CP method, despite utilizing seasonal PRMR and ZRC values, failed to "adjust the nominal MW of customer demand for the seasonality of the resources needed to support that load."[31] To address this claimed

[30] Jester Direct at 18.
[31] *Id.*

shortcoming of the 9-CP method, he proposed his "weighted incremental share of production plant by season" method and indicated that it was his preferred method.[32] Under his "weighted incremental share of production plant by season", witness Jester, instead of focusing on the seasons that drive DTE's total Production Facility capacity need, focuses on the Season that clearly does not, MISO Winter. He essentially argues the percent of DTE's total production facility capacity necessary to meet DTE's MISO Winter PRMR (71.9%) is needed in all seasons and therefore that percentage of DTE's Production Facility Costs should be first allocated to customer classes based on 12-CP demand. He then incrementally works his way up to MISO Spring and argues the additional capacity necessary to cover MISO Spring (24.6% = 96.5% - 71.9%) should be allocated to customer classes on a Spring/Fall/Summer 9-CP demand method. He then further moved incrementally up to MISO Fall and argues the additional necessary capacity to cover MISO Fall (1.6%) should be allocated using a Summer/Fall 6-CP method. Finally, he proposed the amount of additional capacity to get up to 100% and also cover MISO Summer (1.8%) would be allocated using a summer 3-CP (June, July and August) demand method.[33]

Both of MNSC witness Jester's proposals and his rationales underlying them are seriously flawed, inconsistent with cost causation and not supported by the data witness Jester utilized.

Q PLEASE EXPLAIN WHY MNSC WITNESS JESTER'S 9-CP PROPOSAL AND THE RATIONALE UNDERLYING IT ARE SERIOUSLY FLAWED.

A With respect to MNSC witness Jester's 9-CP proposal, his claim about the Commission allocating Production Plant Demand cost based on the months during which DTE

[32] I*d*. at 18-19.
[33] *Id.* at 19.

Electric's Production Plant portfolio is most heavily utilized is not an accurate characterization of how the current 4-CP method was arrived at in Case No. U-17689. The current 4-CP method that was approved in Case No. U-17689 was based on the results of system demand tests, which are used to determine the monthly system peaks that that drive the total amount of production facility capacity DTE needs in order to reliably serve its load over the entire year.[34] The tests explicitly exclude from those monthly system peaks the months where system peak demand does not rise to the level of requiring production facility capacity near that necessary at the annual system peak. Specifically, the system demand tests are designed to determine the months where customer demand at the time of the system peak will affect the total amount of production facility capacity the utility needs. As such, the system demand tests are designed to determine cost causation consistent with cost of service principles, something that utilization does not generally reflect.

This said, if MISO-wide capacity credit requirements (i.e., PRMR) are considered alone, the data MNSC witness Jester utilized that I have summarized in my Table JRD-Rebuttal-1 would potentially support DTE's system demand at the time of MISO Spring, Sumer and Fall <u>seasonal</u> system peaks driving DTE's total required amount of ZRCs. However, it is very important to note that the data does <u>not</u> potentially support a 9-CP (March through November) demand method. It only potentially supports a 5-CP (May through September) demand method at best. The reason for this is twofold.

First, MISO does not allocate seasonal PRMR amounts to Load Serving Entities ("LSEs"), including DTE, on the basis of the LSE's demand at the time of each of the three monthly MISO-wide system peaks of the season, which would be a 3-CP

[34]Case No. U-17689, Final Order, June 15, 2015 at 3-5 and 20.

seasonal allocation method. Instead, MISO allocates seasonal PRMR to LSEs based on the forecasted demand of the LSE at the time of the MISO-wide system peak for the season, which is a 1-CP seasonal allocation method.[35]

Second, it is important to note that the MISO Fall (September through November) and Spring (March through May) seasons each include months within them that have very different characteristics. Specifically, for Fall, September is predominately a cooling load month while November is predominately a heating load month. Similarly, with respect to Spring, May is predominantly a cooling load month while March is predominately a heating load month. Because of this and MISO being a summer peaking system, MISO's Fall MISO-wide and Fall Zone 7 system peaks have always occurred in September and MISO's Spring MISO-wide and Spring Zone 7 system peaks have nearly always occurred in May. This is shown in Exhibit AB-21, which is a file MISO maintains of the date and time of its historical seasonal MISO-wide and Zonal system peaks from January 2016 to date.[36] In this file (Exhibit AB-21), MISO highlights in orange coloring the monthly system peak for each season on which the seasonal system peak occurred. For the MISO Summer and Winter seasons, the seasonal system peak has been fairly evenly distributed over the MISO Summer and Winter months both on a MISO-wide and Zone 7 basis, but for the MISO Fall season the system peak has always occurred in September and for the MISO Spring season the system peak has, except on one occasion, always occurred in May. This is summarizing in Table JRD-Rebuttal-2 below:

[35]MISO Tariff, Module A at Section 1.C and Module E-1 at Section 68A.7.

[36]The version of the file provided in Exhibit AB-21 was accessed on August 11, 2024. The latest version of this file can be accessed from the MISO website at: https://cdn.misoenergy.org/Historical%20Monthly_Seasonal%20Peak%20Dates%20and%20Times%20MISO%20LRZ_Settled%20Load%20(Spring%202024)636872.xlsx.

Table JRD-Rebuttal-2

Historical Frequency of Seasonal System Peak Occurrence
January 2016 through May 2024

MISO Season	Calendar Month	Number of Times Seasonal MISO-wide System Peak Occurred in Month	Number of Times Seasonal MISO Zone 7 System Peak Occurred in Month
Summer	June	2	1
Summer	July	3	5
Summer	August	3	2
Fall	September	8	8
Fall	October	0	0
Fall	November	0	0
Winter	December	2	3
Winter	January	5	5
Winter	February	2	1
Spring	March	1	1
Spring	April	0	0
Spring	May	8	8

Source: Exhibit AB-21

Given these results, it would be appropriate to include June, July and August CP demand for Summer since the MISO-wide seasonal system peak occurs in all three months on a regular basis and, as a result, demand at the time of any of those monthly system peaks could impact the amount of PRMR the LSE (i.e., DTE) is assigned for that season in the future. However, it would not be appropriate to include either October and November CP demand for Fall or March and April CP demand for Spring since the MISO-wide seasonal system peak is unlikely to occur in those months such that demand at the time of the MISO-wide system peaks during these months is unlikely

to impact the amount of PRMR the LSE is assigned in the future for Fall and Spring. For these reasons, as I have indicated, even if DTE's MISO-wide capacity credit requirement for each season could be used alone to determine the appropriate demand allocation for production facility costs, which it cannot, that information at best potentially supports the use of a 5-CP (May, June, July, August and September) demand allocation method, not a March through November 9-CP demand allocation.

Given the reasons I have discussed with respect to why DTE's system peaks are still relevant with respect to determining the appropriate CP method, my update of the system demand tests performed in Case No. U-17689 supporting continuation of a summer (June, July, August and September) 4-CP method for DTE, and DTE's MISO-wide capacity requirements at best potentially supporting a 5-CP (May, June, July, August and September) method, MNSC witness Jester's proposal to change the demand allocation portion of DTE's current 4-CP 75-0-25 production facility cost allocator from the current 4-CP (June, July, August and September) demand method to a 9-CP (March through November) demand method should be rejected and the current 4-CP method continued.

Q PLEASE EXPLAIN WHY MNSC WITNESS JESTER'S "WEIGHTED INCREMENTAL SHARE OF PRODUCTION PLANT BY SEASON" METHOD PROPOSAL AND THE RATIONALE UNDERLYING IT ARE SERIOUSLY FLAWED.

A First, MNSC witness Jester does not explain what he means with respect to why a traditional CP method using ZRCs rather than nominal MW fails to "adjust the nominal MW of customer demand for the seasonality of the resources needed to support that load using ZRCs in place of nominal MW". Nor does he explain how his "weighted

incremental share of production plant by season" method addresses the claimed problem.

Second, MNSC Jester's "weighted incremental share of production plant by season" method is not based on cost causation. As he readily admits in his direct testimony, it is instead based on the idea that "Production Plant capacity should be allocated to customer classes based on the seasons in which the Production Plant is used."[37] Usage and cost causation are not the same. To be clear, the data summarized in Table JRD-Rebuttal-1 shows that DTE has a very large Winter 2024/2025 ZRC surplus equal to 39.1% of its total MISO-wide PRMR for that season. This is very likely due to a combination of DTE's monthly system peaks in December, January and February being 64% to 66% of DTE's annual system peak in the summer[38] and DTE's current production facility fleet likely being accredited a largely similar amount of ZRCs in the winter as in the summer. Given this level of ZRC surplus, customer demand at the time of DTE's December, January and February system peaks is highly unlikely to have any significant impact on DTE's total need for production facility capacity. As a result, allocating demand allocated production facility costs to customer classes based on their demand at the time of those monthly system peaks would not be consistent with cost causation. In addition, shifting the allocation of these costs toward customer demand at the time of the MISO Winter monthly system peaks would necessarily involve shifting costs away from customer demand at the time of the Summer monthly system peaks -- the time when customer demand at the time of the monthly system peaks <u>does</u> impact DTE's total need for production capacity. This would create a cross subsidy and a price signal that would foster inefficient customer behavior.

[37]Jester Direct at 19.
[38]Exhibit AB-20 at lines 1, 2 and 12.

Given all of the above, MNSC witness Jester's proposal to change the demand allocation of DTE's current 4-CP 75-0-25 production facility cost allocator from the current 4-CP method to witness Jester's "weighted incremental share of production plant by season" method should be rejected and the current 4-CP method continued for the reasons I have previously discussed in this testimony. Also, as I earlier noted, given MNSC witness Jester's production facility cost rate design proposal is contingent on Commission adoption of one of his proposed changes to the demand portion DTE's production plant cost allocator, that proposal should be rejected as well.

III. Response to MNSC Distribution Rate Design Proposal

Q PLEASE BRIEFLY DESCRIBE MNSC WITNESS JESTER'S PROPOSAL TO CHANGE THE RATE DESIGN FOR DISTRIBUTION COSTS.

A Leveraging the direct testimony of MNSC witnesses Gard and Woolley with respect to transformer loss of life and the temperature impact on distribution facility ratings,[39] MSC witness Jester argues the proper basis of both cost of service and rate design of distribution costs is the degree of capacity utilization, not nominal loading and, thus, the rates should be seasonal. While he makes this argument, his requested relief is limited to asking the Commission to direct DTE to submit in its next rate case a seasonal approach to distribution rates reflecting that the relative utilization of the distribution system is seasonal.[40]

[39] Jester Direct at 23-26.
[40] Jester Direct at 44.

Q HOW DO YOU RESPOND?

A In general, utilization does not align with cost causation unless either the cost in question involves incurring a variable cost based on utilization or the utilization period being used is limited to demand in the specific hours that cause the utility to incur infrastructure costs. In this regard, just because the loss of life of a distribution transformer may be higher in certain seasons than others, it does not mean the allocation of all distribution costs should be based on seasonal utilization even if distribution equipment ratings are sensitive to ambient temperature. This said, given MNSC witness Jester has not requested the Commission to find in this proceeding that distribution rates be based on seasonal utilization, only that the Commission require certain information be filed by DTE in its next rate case filing, I will at this time simply reserve ABATE's right to respond to any proposal in future rate case proceedings that the Commission require DTE to adopt either a distribution class cost of service method, or a distribution rate design, that is based on seasonal utilization.

IV. Response to MEIU Proposal to Require DTE to Revise its Transmission Electrification Plan to Account for Societal Benefits

Q PLEASE BRIEFLY DESCRIBE MEIU WITNESS SHERMAN'S PROPOSAL TO REQUIRE DTE TO CHANGE ITS TRANSMISSION ELECTRIFICATION PLAN ("TEP") BENEFIT TO COST ANALYSIS ("BCA") TO ACCOUNT FOR SOCIETAL BENEFITS.

A MEIU witness Sherman presents extensive testimony that argues that the Commission should require DTE to account for societal benefits, including greenhouse gas and criteria pollutant emissions reductions, in its BCA for its TEP.[41] While ABATE would

[41]Sherman Direct at 24-36 and 64.

not object to the use of the SCT ("Societal Cost Test") for informational purposes as a sensitivity case, the Commission should not order the use of the SCT, or any other the inclusion of societal benefits, including greenhouse gas and criteria pollutant emissions, in DTE's base case BCA for its TEP. In addition, the Commission should not direct DTE to pursue or expand its TEP on the basis of societal benefits associated with avoided transportation emissions, as that would amount to mandating electric ratepayers to subsidize the cost of providing the claimed societal benefits. To the extent the Commission grants the request of MEIU witness Sherman, it should be limited to the provision of a sensitivity case for the BCA for the DTE TEP.

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the Application of 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 and Exhibits of

Christopher C. Walters

On behalf of

Association of Businesses Advocating Tariff Equity

July 26, 2024

BRUBAKER & ASSOCIATES, INC.

Project 11638

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**

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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**

Direct Testimony of Christopher C. Walters

I. INTRODUCTION

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Christopher C. Walters. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Association of Businesses Advocating Tariff Equity ("ABATE"). ABATE consists of large usage customers that purchase substantial amounts of electric power and/or delivery service from DTE Electric Company ("DTE"

or "Company"). They primarily take service under DTE Rate D8, Rate D11, Rider 3 and/or Rider 10.

Q HAVE YOU PRESENTED TESTIMONY IN PRIOR ELECTRIC REGULATORY PROCEEDINGS BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION ("COMMISSION")?

A Yes, I have.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A My testimony addresses a fair return on equity ("ROE") that balances the interests of ratepayers and shareholders.

My silence with regard to any position taken by DTE in its application or direct testimony in this proceeding does not indicate my endorsement of that position.

II. SUMMARY

Q PLEASE BRIEFLY SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS IN THIS PROCEEDING.

A In Section III of my testimony, I review and analyze the regulated utility industry's access to capital, credit rating trends, and outlooks, as well as the overall trend in the authorized ROE for utilities throughout the country. I conclude that the trend in authorized ROEs for utilities has declined over the last several years and has remained below 10.0% in more recent history. I also review the impact that the Federal Reserve's (the "Fed") monetary policy actions have had on the cost of capital.

In Section IV of my testimony, I outline how a fair ROE should be established, provide an overview of the market's perception of the Company's investment risk,

comment on the Company's proposed capital structure, and present the analyses I relied on to estimate an appropriate ROE for DTE. Based on the results of several cost of equity estimation methods performed on publicly traded utility companies, I estimate the current fair market ROE for the Company to fall within the range of 9.20% to 10.00%. Based on my assessment of the Company's overall risk profile and the results of the analytical methods, I recommend DTE be awarded an ROE of 9.60%, which is the mid-point of my estimated range.

In Section V of my testimony, I respond to Company witness Dr. Villadsen's estimate of the current market cost of equity for DTE. Dr. Villadsen recommends the Company be authorized an ROE of 10.50%. I demonstrate that Dr. Villadsen's ROE recommendations are excessive and should be rejected.

Based on all of the foregoing, I request this Commission adopt the following recommendations:

1. Reject DTE's proposed ROE of 10.50% and instead adopt my recommended ROE of 9.60%, which is based on my assessment of the current and expected capital market environment, the Company's overall risk profile, and the results of several analytical methods which I have analyzed, to determine a fair and reasonable ROE to be authorized for DTE.

2. My recommendations produce an overall ratemaking ROR of 5.57% and would reduce DTE's Michigan electric retail revenue requirements by approximately $105.5 million.

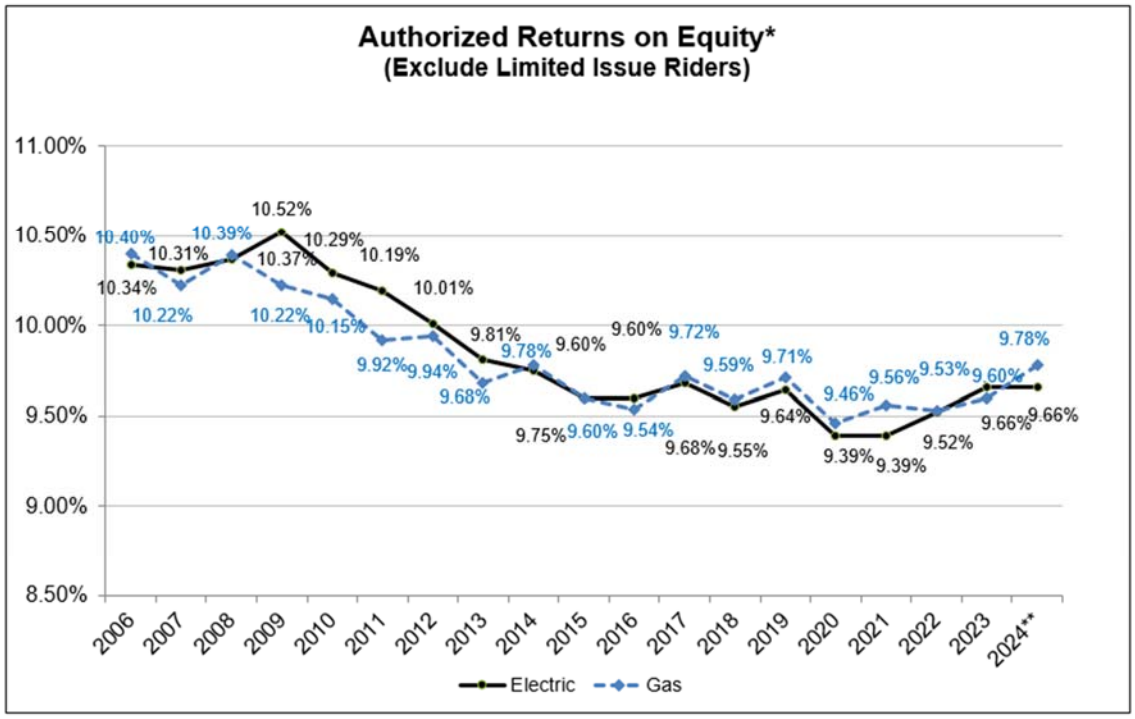
III. INDUSTRY TRENDS AND ECONOMIC ENVIRONMENT

A. Regulated Utility Industry Authorized ROEs, Access to Capital, and Credit Strength

Q PLEASE DESCRIBE THE OBSERVABLE EVIDENCE ON TRENDS IN AUTHORIZED ROEs FOR ELECTRIC AND GAS UTILITIES.

A Authorized ROEs for both electric and gas utilities have declined over the last 10 years, as illustrated in Figure CCW-1, and have been below 10.0% for about the last nine years.

FIGURE CCW-1



Source and Notes:
* Electric Returns exclude Limited Issue Riders.
** *S&P Global Market Intelligence*, RRA Regulatory Focus, Major Rate Case Decisions -- January - March 2024, April 19, 2024 at page 3.

Q PLEASE DESCRIBE THE DISTRIBUTION OF AUTHORIZED ROEs FOR ELECTRIC UTILITIES FOR THE LAST FEW YEARS.

A The distribution of authorized returns, annually, since 2016 is summarized in Table CCW-1.

TABLE CCW-1

Distribution of Authorized ROEs
(All Electric Utilities)*

Year (1)	Average (2)	Median (3)	Share of Decisions ≤ 9.5%	Share of Decisions ≤ 9.7%	Share of Decisions ≤ 10.0%
2016	9.60%	9.60%	41%	53%	94%
2017[1]	9.67%	9.60%	42%	67%	81%
2018[2]	9.54%	9.57%	47%	63%	100%
2019	9.64%	9.65%	39%	58%	88%
2020[3]	9.38%	9.48%	64%	79%	100%
2021	9.39%	9.49%	58%	81%	97%
2022	9.52%	9.50%	53%	63%	84%
2023	9.66%	9.60%	38%	65%	85%
2024	9.70%	9.75%	15%	46%	100%
Average	9.57%	9.58%	44%	64%	92%
Median	9.60%	9.60%	42%	63%	94%

Source and Notes:
S&P Global Market Intelligence, data through June 21, 2024.
[1]Includes authorized base ROE of 9.4% for Nevada Power Company, which excludes incentives associated with the Lenzie facility.
[2]Includes authorized base ROE of 9.6% for Interstate Power & Light Co., which excludes allowed ROE for generating facilities subject to special ratemaking principles.
[3]Includes authorized base ROE of 9.8% for Interstate Power & Light Co., which excludes allowed ROE for generating facilities subject to special ratemaking principles.
*Excludes Limited Issue Rider Cases.

The distribution shows that over the last few years, the majority of authorized ROEs since 2016 have been below 9.7%, with many of those being below 9.5%.

Q HOW HAS THE AUTHORIZED COMMON EQUITY RATIO FLUCTUATED OVER THE SAME TIME PERIOD FOR UTILITIES?

A In general, the utility industry's common equity ratio has not really deviated too much from the range of 50.0% to 52.0%. As shown in Table CCW-2 below, I have provided the authorized common equity ratios for utilities around the country, excluding the reported common equity ratios for Arkansas, Florida, Indiana, and Michigan. For my overall market analysis, I have excluded the reported authorized common equity ratios for these states because these jurisdictions include sources of capital outside of investor-supplied capital such as accumulated deferred income taxes. As such, the reported common equity ratios in these states would result in a downward bias in the reported permanent common equity ratios authorized for ratemaking purposes within my trend analysis.

TABLE CCW-2

Trends in State Authorized Common Equity Ratios
(Industry)

	Electric[1]	
Year	Average	Median
(1)	(2)	(3)
2016	49.70%	49.99%
2017	50.02%	49.85%
2018	50.60%	50.23%
2019	51.55%	51.37%
2020	50.94%	51.17%
2021	51.01%	52.00%
2022	51.57%	51.92%
2023	51.59%	52.27%
2024	50.65%	51.90%
Average	50.85%	51.19%
Median	50.94%	51.37%

Source and Notes:
[1] S&P Global Market Intelligence, data through June 21, 2024.
[2] Excludes Arkansas, Florida, Indiana, and Michigan, because they include non-investor capital.

Q HAVE REGULATED UTILITY COMPANIES BEEN ABLE TO MAINTAIN RELATIVELY STRONG CREDIT RATINGS DURING PERIODS OF DECLINING AUTHORIZED ROEs?

A Yes. As shown below in Table CCW-3, the credit ratings of the industry have improved since 2009. In 2009, approximately 53% of the industry was rated BBB+ or higher. Currently, 88% of the industry has a rating of BBB+ or higher.

TABLE CCW-3

S&P Ratings by Category
Electric Utility Subsidiaries
(Year End)

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
A or higher	12%	12%	12%	11%	13%	13%	13%	10%	10%	8%	14%	14%	10%	10%	12%	13%
A-	18%	20%	19%	22%	26%	26%	34%	43%	52%	54%	54%	53%	37%	37%	37%	33%
BBB+	23%	24%	28%	28%	25%	28%	24%	32%	21%	22%	18%	19%	35%	36%	36%	42%
BBB	36%	26%	24%	22%	26%	23%	18%	4%	7%	13%	12%	3%	16%	16%	15%	12%
BBB-	9%	16%	15%	17%	11%	11%	11%	11%	11%	2%	1%	1%	0%	0%	0%	0%
Below BBB-	2%	2%	2%	0%	0%	0%	0%	0%	0%	0%	0%	10%	1%	1%	1%	1%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Source: S&P CAPITAL IQ and Market Intelligence, downloaded 6/21/2024.
Note: Subsidiary ratings used.

Q HAVE UTILITIES BEEN ABLE TO ACCESS EXTERNAL CAPITAL TO SUPPORT CAPITAL EXPENDITURE PROGRAMS?

A Yes. In Regulatory Research Associates' ("RRA") April 2, 2024 Utility Capital Expenditures report, *RRA Financial Focus*, a division of S&P Global Market Intelligence, made several relevant comments about utility investments generally:

- Multiple drivers are expected to elevate utility capital expenditures over the next several years. Pent-up demand to replace aging equipment continues to propel considerable utility investments in infrastructure, while artificial intelligence increases the power demands of datacenters daily.

- Projected 2024 capital expenditure for the 45 energy utilities included in the RRA representative sample of publicly traded, US-based utilities is $184 billion — an upswell of nearly 11% from the group's $166 billion of actual spending in 2023. The increase is largely driven by federal legislation enacted in 2021 and 2022 supporting infrastructure investment.

* * *

- Aggregated energy utility capex estimates for both 2024 and 2025 indicate successively higher spending levels, reaching $184 billion and $191 billion, respectively. Spending expectations for 2024 and beyond are likely to increase as the companies' plans for future projects continue to solidify around the new federal legislation supporting infrastructure investment.

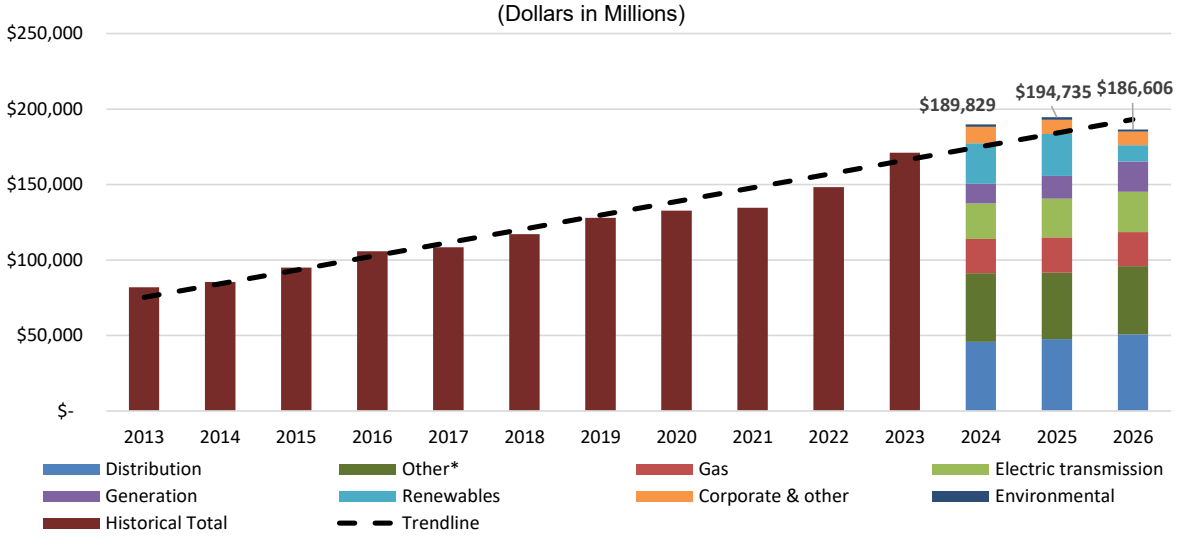
- Utilities have multiple opportunities to finance and support energy investments through mechanisms available within the Inflation Reduction Act and the Infrastructure Investment and Jobs Act of 2021.

These pieces of legislation provide billions of dollars for power infrastructure investments, financial incentives for nuclear power plants and funding for battery storage technology, among other provisions.[1]

As shown in Figure CCW-2 below, capital expenditures for the regulated electric and natural gas delivery utilities have increased considerably over the period 2023 into 2024, and the forecasted capital expenditures remain elevated through the end of 2025. The outlooks for electric and natural gas industries reasonably align with capital expenditure outlooks for water utilities as noted by RRA above.

FIGURE CCW-2

Utility Capital Expenditures
(Dollars in Millions)



*Other category consists of utilities that do not report capital expenditures by category: Avangrid, Hawaiian Electric, PG&E and Portland General Electric.
Source: *S&P Global Market Intelligence, RRA Financial Focus*, Utility Capital Expenditures Update, March 27, 2024, Tables 1 and 3.

As demonstrated in Figure CCW-2 above, and in the comments made by *RRA S&P Global Market Intelligence*, capital investments for the utility industry continue to stay at elevated levels, and these capital expenditures are expected to fuel utilities' profit growth into the foreseeable future. This is clear evidence that the capital investments are enhancing shareholder value and are attracting both equity and debt capital to the utility industry in a manner that allows for funding these elevated capital

[1] *S&P Global Market Intelligence, RRA Financial Focus*: "Utility capex primed for profusion in 2024 and beyond," April 2, 2024.

investments. While capital markets embrace these profit-driven capital investments, regulatory commissions also must be careful to maintain reasonable prices and tariff terms and conditions to protect customers' need for reliable utility service at reasonable rates. If this is not done, utility rates will expand beyond the ability of customers to pay, resulting in revenue constraints for utilities, which will impact their financial integrity.

Q WHAT IS THE SIGNIFICANCE OF THESE FINDINGS?

A This is clear evidence that the capital investments are enhancing shareholder value, and are attracting both equity and debt capital to the utility industry in a manner that allows for these elevated capital investments.

Q IS THERE EVIDENCE OF ROBUST VALUATIONS OF REGULATED UTILITY EQUITY SECURITIES?

A Yes. Robust valuations are an indication that utilities can sell securities at high prices, which is a strong signal that they can access equity capital under reasonable terms and conditions, and at relatively low cost. As shown on Exhibit AB-4, the historical valuation of utilities followed by *The Value Line Investment Survey* ("*Value Line*"), based on a price-to-earnings ("P/E") ratio, price-to-cash flow ("P/CF") ratio, and market price-to-book value ("M/B") ratio, indicates utility security valuations today are very strong and robust relative to the last several years. These strong valuations of utility stocks indicate that utilities have access to equity capital under reasonable terms and at lower costs.

Q WHAT CONCLUSION DO YOU DRAW FROM THIS OBSERVABLE MARKET DATA IN FORMING YOUR RECOMMENDED ROE AND OVERALL RATE OF RETURN?

A Generally, authorized ROEs, credit standing, and access to capital have been quite robust for utilities over the last several years, even throughout the duration of the global pandemic. It is critical that this Commission ensure that utility rates are increased no more than necessary to provide fair compensation and maintain financial integrity.

B. Impact of Monetary Policy

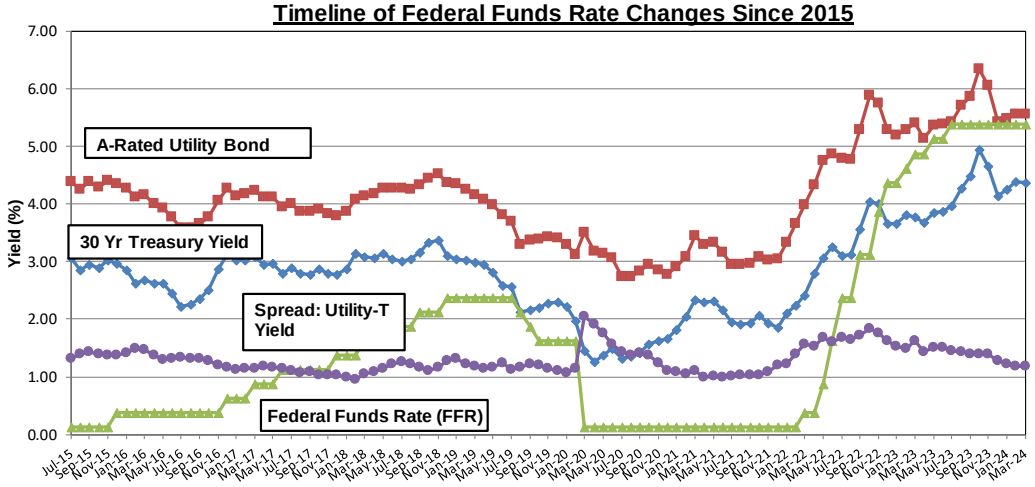
Q ARE THE FEDERAL OPEN MARKET COMMITTEE'S ("FOMC") ACTIONS KNOWN TO THE MARKET PARTICIPANTS, AND IS IT REASONABLE TO BELIEVE THEY ARE REFLECTED IN THE MARKET'S VALUATION OF BOTH DEBT AND EQUITY SECURITIES?

A Yes to both questions. The Fed has been transparent about its efforts to support the economy to achieve maximum employment, and to manage long-term inflation to around a 2% level. The Fed has implemented procedures to support the economy's efforts to achieve these policy objectives. Specifically, the Fed had previously lowered the Federal Overnight Rate for securities and had engaged in a Quantitative Easing program where the Fed was buying, on a monthly basis, Treasury and mortgage-backed securities in order to moderate the demand in the marketplaces and support the economy. Currently, the Fed is reducing its holdings of Treasury securities and agency debt and agency mortgage-backed securities. Such monetary policy actions include raising the target federal funds rate and allowing maturing bonds to roll off its balance sheet.

A visualization of the market's reaction to the Fed's actions on the federal funds rate is shown below in Figure CCW-3.

FIGURE CCW-3

Timeline of Federal Funds Rate Changes Since 2015



Fed FFR Actions:

1	December 2015	0.25	→	0.50	14	March 2020	0.00	→	0.25
2	December 2016	0.50	→	0.75	15	March 2022	0.25	→	0.50
3	March 2017	0.75	→	1.00	16	May 2022	0.75	→	1.00
4	June 2017	1.00	→	1.25	17	June 2022	1.50	→	1.75
5	December 2017	1.25	→	1.50	18	July 2022	2.25	→	2.50
6	March 2018	1.50	→	1.75	19	September 2022	3.00	→	3.25
7	June 2018	1.75	→	2.00	20	November 2022	3.75	→	4.00
8	September 2018	2.00	→	2.25	21	December 2022	4.25	→	4.50
9	December 2018	2.25	→	2.50	22	February 2023	4.50	→	4.75
10	August 2019	2.00	→	2.25	23	March 2023	4.75	→	5.00
11	September 2019	1.75	→	2.00	24	May 2023	5.00	→	5.25
12	October 2019	1.50	→	1.75	25	July 2023	5.25	→	5.50
13	March 2020	1.00	→	1.25					

Sources:
Federal Reserve Bank of New York, https://apps.newyorkfed.org/markets/autorates/fed-funds-search-page
Board of Governors of the Federal Reserve System, https://www.federalreserve.gov/datadownload/
Moody's Credit Trends, https://credittrends.moodys.com/

As shown in Figure CCW-3 above, the rise in the Federal Funds Rate has far outpaced the rise in Utility and Treasury yields while the spread of Utility bonds over Treasury bond yields have stabilized recently.

Q HAS THE FED MADE RECENT COMMENTS CONCERNING MONETARY POLICY AND THE POTENTIAL IMPACT ON INTEREST RATES?

A Yes. In its recent press release, the FOMC stated the following:

> Recent indicators suggest that economic activity has continued to expand at a solid pace. Job gains have remained strong, and the unemployment rate has remained low. Inflation has eased over the past

> year but remains elevated. In recent months, there has been a lack of further progress toward the Committee's 2 percent inflation objective.
>
> The Committee seeks to achieve maximum employment and inflation at the rate of 2 percent over the longer run. The Committee judges that the risks to achieving its employment and inflation goals have moved toward better balance over the past year. The economic outlook is uncertain, and the Committee remains highly attentive to inflation risks.
>
> In support of its goals, the Committee decided to maintain the target range for the federal funds rate at 5-1/4 to 5-1/2 percent. In considering any adjustments to the target range for the federal funds rate, the Committee will carefully assess incoming data, the evolving outlook, and the balance of risks. The Committee does not expect it will be appropriate to reduce the target range until it has gained greater confidence that inflation is moving sustainably toward 2 percent. In addition, the Committee will continue reducing its holdings of Treasury securities and agency debt and agency mortgage-backed securities. Beginning in June, the Committee will slow the pace of decline of its securities holdings by reducing the monthly redemption cap on Treasury securities from $60 billion to $25 billion. The Committee will maintain the monthly redemption cap on agency debt and agency mortgage-backed securities at $35 billion and will reinvest any principal payments in excess of this cap into Treasury securities. The Committee is strongly committed to returning inflation to its 2 percent objective.
>
> In assessing the appropriate stance of monetary policy, the Committee will continue to monitor the implications of incoming information for the economic outlook. The Committee would be prepared to adjust the stance of monetary policy as appropriate if risks emerge that could impede the attainment of the Committee's goals. The Committee's assessments will take into account a wide range of information, including readings on labor market conditions, inflation pressures and inflation expectations, and financial and international developments.[2]

The above quotes suggest the FOMC has had some success in taming inflation over the last year, though not as much in recent months. It further reiterated its commitment to stabilizing consumer prices and promoting maximum employment through its monetary policy tools.

[2]Found here: https://www.federalreserve.gov/newsevents/pressreleases/monetary20240501a.htm, May 1, 2024.

Q WHAT DO INDEPENDENT ECONOMISTS' OUTLOOKS FOR FUTURE INTEREST RATES INDICATE?

A Independent economists, surveyed by *Blue Chip Financial Forecasts,* expect current capital costs to increase at mixed rates over the near term, while maintaining levels that are still low by historical standards. For example, independent projections show that the consensus is the federal funds rate will increase at a rate much faster than that of long-term interest rates as measured by the 30-year Treasury bond. Inflation, as measured through the Gross Domestic Product ("GDP") price index, is expected to cool off in the near to intermediate term.

The consensus projections for the next several quarters are provided in Table CCW-4 below.

TABLE CCW-4

Blue Chip Financial Forecasts
Projected Federal Funds Rate, 30-Year Treasury Bond Yields, and GDP Price Index

Publication Date	4Q 2022	1Q 2023	2Q 2023	3Q 2023	4Q 2023	1Q 2024	2Q 2024	3Q 2024	4Q 2024	1Q 2025	2Q 2025	3Q 2025
Federal Funds Rate												
Feb-23	3.7	4.7	5.0	4.9	4.7	4.3	4.0					
Mar-23	**3.7**	4.7	5.1	5.1	5.0	4.7	4.2					
Apr-23		4.5	5.0	5.1	4.9	4.6	4.2	3.8				
May-23		4.5	5.0	5.1	5.0	4.7	4.2	3.8				
Jun-23		**4.5**	5.0	5.1	5.0	4.6	4.2	3.9				
Jul-23			5.0	5.3	5.2	5.0	4.6	4.3	3.9			
Aug-23			5.0	5.4	5.4	5.2	4.9	4.4	4.0			
Sep-23			**5.0**	5.3	5.4	5.3	5.0	4.6	4.2			
Oct-23				5.3	5.4	5.4	5.1	4.7	4.3	4.0		
Nov-23				5.3	5.4	5.4	5.2	4.9	4.5	4.1		
Dec-23				**5.3**	5.4	5.4	5.2	4.9	4.6	4.2		
Jan-24					5.3	5.3	5.1	4.8	4.4	4.1	3.8	
Feb-24					5.3	5.3	5.1	4.7	4.4	4.1	3.8	
Mar-24					**5.3**	5.4	5.2	4.9	4.5	4.2	3.8	
Apr-24						5.3	5.2	5.0	4.6	4.2	3.9	3.7
May-24						5.3	5.4	5.2	4.9	4.6	4.3	4.0
Jun-24						**5.3**	5.4	5.2	5.0	4.7	4.4	4.1
T-Bond, 30 yr.												
Feb-23	3.9	3.8	3.9	3.9	3.8	3.8	3.7					
Mar-23	**3.9**	3.9	4.0	3.9	3.9	3.8	3.8					
Apr-23		3.8	3.9	3.8	3.8	3.8	3.8	3.7				
May-23		3.7	3.8	3.8	3.8	3.8	3.7	3.7				
Jun-23		**3.7**	3.8	3.8	3.8	3.8	3.8	3.7				
Jul-23			3.8	3.9	3.9	3.9	3.8	3.8	3.8			
Aug-23			3.8	4.0	3.9	4.0	3.9	3.9	3.8			
Sep-23			**3.8**	4.1	4.2	4.1	4.0	4.0	3.9			
Oct-23				4.2	4.4	4.3	4.2	4.2	4.1	4.0		
Nov-23				4.2	4.8	4.7	4.5	4.5	4.3	4.2		
Dec-23				**4.2**	4.8	4.7	4.5	4.5	4.4	4.3		
Jan-24					4.6	4.3	4.3	4.2	4.1	4.0	4.0	
Feb-24					4.6	4.3	4.2	4.2	4.1	4.0	4.0	
Mar-24					**4.6**	4.4	4.3	4.2	4.2	4.1	4.1	
Apr-24						4.3	4.3	4.2	4.2	4.1	4.1	4.0
May-24						4.3	4.6	4.5	4.4	4.3	4.2	4.2
Jun-24						**4.3**	4.6	4.5	4.5	4.4	4.3	4.3
GDP Price Index												
Feb-23	3.5	3.3	3.0	2.7	2.6	2.4	2.3					
Mar-23	**3.9**	3.2	2.8	2.6	2.5	2.5	2.3					
Apr-23		3.2	3.2	2.9	2.7	2.5	2.3	2.2				
May-23		4.0	3.2	2.9	2.7	2.5	2.3	2.2				
Jun-23		**4.2**	3.3	2.8	2.7	2.5	2.5	2.2				
Jul-23			3.3	2.9	2.8	2.5	2.4	2.2	2.2			
Aug-23			2.2	2.7	2.6	2.5	2.3	2.3	2.3			
Sep-23			**2.0**	2.7	2.6	2.4	2.3	2.2	2.2			
Oct-23				2.7	2.7	2.4	2.2	2.2	2.2	2.2		
Nov-23				3.5	2.7	2.4	2.3	2.2	2.2	2.3		
Dec-23				**3.6**	2.7	2.4	2.3	2.2	2.2	2.2		
Jan-24					2.7	2.3	2.3	2.3	2.2	2.2	2.1	
Feb-24					1.5	2.2	2.2	2.3	2.2	2.2	2.1	
Mar-24					**1.6**	2.2	2.3	2.2	2.2	2.1	2.1	
Apr-24						2.2	2.4	2.3	2.2	2.2	2.1	2.2
May-24						3.1	2.7	2.4	2.3	2.3	2.2	2.2
Jun-24						**3.0**	2.8	2.5	2.3	2.3	2.3	2.2

Source and Note:
Blue Chip Financial Forecasts, Jan 2022 through June 2024.
Actual Yields in Bold.

Further, the outlook for long-term interest rates in the intermediate to long term is also impacted by the current Fed actions and the expectation that eventually the Fed's monetary actions will return to more-normal levels. Long-term interest rate projections are illustrated in Table CCW-5 below.

TABLE CCW-5

30-Year Treasury Bond Yield Actual Vs. Projection

Description	Actual	Near-Term Projected*	5- to 10-Year Projected
2020			
Q1	1.88%	2.57%	
Q2	1.38%	1.90%	3.0% - 3.8%
Q3	1.36%	1.87%	
Q4	1.62%	1.97%	2.8% - 3.6%
2021			
Q1	2.07%	2.23%	
Q2	2.26%	2.77%	3.5% - 3.9%
Q3	1.93%	2.63%	
Q4	1.95%	2.70%	3.4% - 3.8%
2022			
Q1	2.25%	2.87%	
Q2	3.04%	3.47%	3.8% - 3.9%
Q3	3.26%	3.63%	
Q4	3.90%	3.87%	3.9% - 4.0%
2023			
Q1	3.74%	3.77%	
Q2	3.80%	3.70%	3.8% - 3.9%
Q3	4.24%	3.83%	
Q4	4.58%	4.17%	4.1% - 4.2%
2024			
Q1	4.33%	4.03%	

Source and Note:
Blue Chip Financial Forecasts, January 2019 through March 2024.
*Average of all 3 reports in Quarter.

As outlined in Table CCW-5 above, the outlook for increases in interest rates has jumped more recently relative to 2020 and part of 2021, but is still relatively modest

compared to time periods prior to the beginning of the worldwide pandemic. Indeed, relatively low capital market costs are expected to prevail at least in the near-term and out over the next five to ten years. While there is potential for some upward movement in the cost of capital, that upward movement is uncertain. In fact, as shown on Figure CCW-3 above, increases in the federal funds rate do not necessarily translate into increases in longer-term yields.

C. Market Sentiments and Utility Industry Outlook

Q PLEASE DESCRIBE THE CREDIT RATING OUTLOOK FOR REGULATED UTILITIES.

A All credit rating agencies see rate affordability as an important consideration in assessing utility credit, including Standard & Poor's ("S&P") and Moody's Investors Service ("Moody's") as discussed below.

In 2024, S&P updated its industry outlook to "Negative," stating the following:

> **Key Takeaways**
>
> - We are updating our 2024 outlook on the investor-owned North American regulated utility industry to negative.
>
> - Given the relatively high percentage of companies with negative outlooks, we expect that 2024 will likely be the fifth consecutive year that downgrades outpace upgrades.
>
> - The industry faces rising physical risks and high cash flow deficits that may not be sufficiently funded in a credit-supportive manner.
>
> - Still, we expect that the utility industry will maintain a median investment-grade rating of 'BBB+'.
>
> - We also expect that a smaller percentage of companies rated 'BBB' or lower are more likely to implement measures to maintain or even improve credit quality.[3]

[3] *S&P Global Ratings*: "Rising Risks: Outlook For North American Investor-Owned Regulated Utilities Weakens," February 14, 2024 at 1.

Specifically, in S&P's utility report, it notes that the credit quality of the industry has changed to BBB+ from an A- rating over the last few years. It notes the recently increased interest rates, which are expected to stabilize and ease the pressure on utilities financial performance. S&P also comments on the narrowing spread between utilities authorized returns and the 10-year Treasury yield, which hinders the financial performance of the industry. The credit rating agency expects continued robust capital spending for utilities, projecting over $200 billion investment in 2025. S&P believes that the risks around the industry outlook include regulatory risks in responding to capital spending and the practice of many companies operating with minimal financial cushion from their downgrade thresholds.[4]

Q HAVE CREDIT AGENCIES NOTED CONCERN ABOUT RATE AFFORDABILITY AS A CREDIT RISK TO UTILITIES?

A Yes. Credit rating agencies have been emphasizing rate affordability, maintaining adequate financial coverages of debt obligations, and supporting utilities' overall investment grade bond ratings.

In a recent industry report, Moody's explained that the regulated electric and gas utilities' outlook remains "Negative" largely due to increased pricing pressures on customers. Moody's stated that it changed its outlook from "Positive" to "Negative" due to the following:

> We have revised our outlook on the US regulated utilities sector to negative from stable. We changed the outlook because of increasingly challenging business and financial conditions stemming from higher natural gas prices, inflation and rising interest rates. These developments raise residential customer affordability issues, increasing

[4] *Id*.

> the level of uncertainty with regard to the timely recovery of costs for fuel and purchased power, as well as for rate cases more broadly.[5]

Also, in a report published in January of 2024, S&P specifically mentioned commodity price volatility, in combination with significant increases in capital investments, driving utility rate increases which may strain affordability concerns.[6]

Finally, Fitch opined that the regulated electric and gas utilities' outlook is deteriorating due to elevated capex that put pressure on credit metrics. Fitch also notes the bill affordability concerns for ratepayers, and regulators' ability to balance the rate requests with increasing customer bills.

Specifically, Fitch states:

> Fitch Ratings' deteriorating outlook for the North American Utilities, Power & Gas sector reflects continuing macroeconomic headwinds and elevated capex that are putting pressure on credit metrics in the high-cost funding environment. Bill affordability concerns for ratepayers continue to persist despite the pull back in natural gas prices and inflationary pressures. Fitch expects utility capex to grow by double digits in 2024, underpinned by investments needed to make the electric infrastructure more resilient against extreme weather events and to accommodate renewable generation, including distributed sources. Rate case outcomes are key to watch as regulators balance more rate requests with increases in customer bills. Authorized ROEs could prove to be sticky despite an increase in cost of capital. Higher weather-normalized retail electricity sales, driven by datacenter growth and onshoring of manufacturing activities, and tax transferability provisions of the Inflation Reduction Act could somewhat offset headwinds to utilities. Ongoing management actions to sell assets and issue equity, in some cases, is supportive of parent companies' ratings. Within Fitch's coverage, 90% of ratings hold Stable Rating Outlooks. We expect limited rating movement in 2024. The number of upgrades in 2023 so far exceeds the number of downgrades, and is driven by positive rating actions on several parent holding companies and their regulated subsidiaries.[7]

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[5] *Moody's Investors Service Outlook*: "Regulated Electric and Gas Utilities – US 2023 outlook negative due to higher natural gas prices, inflation and rising interest rates," November 10, 2022 at 1. (emphasis added).

[6] *S&P Global Ratings*: "Industry Credit Outlook 2024: North America Regulated Utilities," January 9, 2024, at 8.

[7] *FitchRatings.* "North American Utilities, Power & Gas Outlook 2024," December 6, 2023 at 1. (emphasis added)

As outlined by Moody's, S&P and Fitch above, credit analysts are focusing on rate affordability as an important factor needed to support strong credit standing. Customers must be able to afford to pay their utility bills in order for utilities to maintain their financial integrity and strong investment grade credit standing. For this reason, this Commission should carefully assess the reasonableness of cost of service in this proceeding, including an appropriate overall rate of return necessitated by a reasonably cost-effective balanced ratemaking capital structure, and a return on equity that represents fair compensation but also maintains competitive, just and reasonable rates.

D. Additional Remarks

Q IN LIGHT OF HIGHER LEVELS OF INFLATION, EXPECTATIONS OF HIGHER INTEREST RATES, AND GEOPOLITICAL EVENTS AROUND THE WORLD, HOW HAS THE MARKET PERCEIVED UTILITIES AS INVESTMENT OPTIONS?

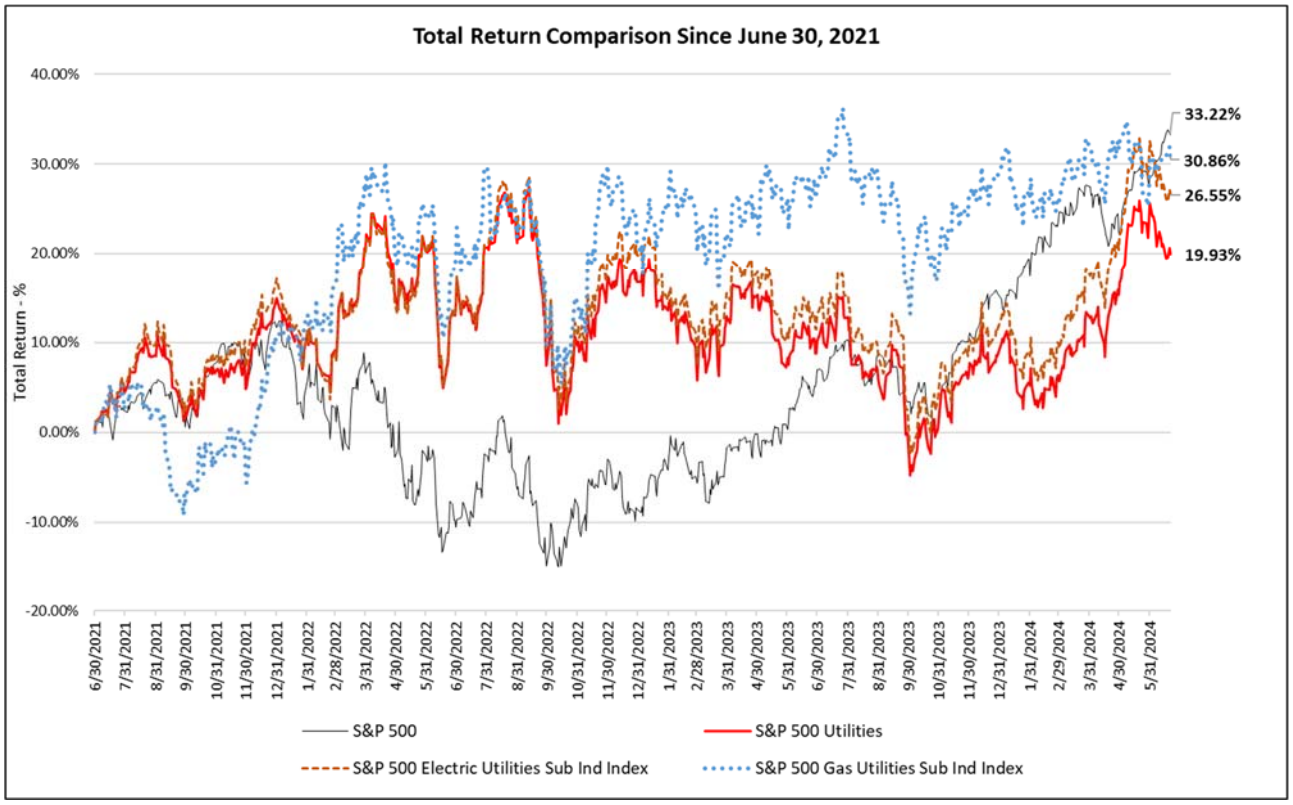
A In 2023, the utility sector underperformed the S&P 500 and has continued to do so in 2024. This is presented below in Figure CCW-4. However, it should be noted that the performance of the S&P 500 has largely been driven by a handful of "mega cap" companies. Because the S&P 500 is a market capitalization weighted index (meaning the higher the market capitalization a company has, the more influence it has on the index's performance). For example, in the S&P Dow Jones Indices report "U.S. Equity Market Attributes April 2024," it is noted that:

> Year-to-date, the S&P 500 remained up 5.57% (with 10 of the 11 sectors up; Real Estate was down 9.86%), as breadth declined but remained positive (302 up and 199 down, compared to last March's 369 and 134 YTD, respectively). The Magnificent 7 as a group still dominated, accounting for 51% of the index return (which included Apple's 11.5% YTD decline and Tesla's 26.2% YTD decline), as NVIDIA (up 74.5% YTD) represented 41% of the S&P 500's YTD gain.[8]

[8]https://www.spglobal.com/spdji/en/documents/commentary/market-attributes-us-equities-202404.pdf

Notwithstanding its recent underperformance relative to the S&P 500, the industry has been able to deliver generally positive and relatively stable returns during a period of elevated inflation, rising interest rates, and uncertainty because of geopolitical events around the world.

Figure CCW-4



IV. RETURN ON EQUITY

Q PLEASE DESCRIBE WHAT IS MEANT BY A "UTILITY'S COST OF COMMON EQUITY."

A A utility's cost of common equity is the expected return that investors require on an investment in the utility. Investors expect to earn their required return from receiving dividends and through stock price appreciation.

Q PLEASE DESCRIBE THE FRAMEWORK FOR DETERMINING A REGULATED UTILITY'S COST OF COMMON EQUITY.

A In general, determining a fair cost of common equity for a regulated utility has been framed by two hallmark decisions of the U.S. Supreme Court: Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944). In these decisions, the Supreme Court found that just compensation depends on many circumstances and must be determined by fair and enlightened judgments based on relevant facts. The Court also found that a utility is entitled to such rates as would permit it to earn a return on a property devoted to the convenience of the public that is generally consistent with the same returns available in other investments of corresponding risk. The Court continued that the utility has "no constitutional rights to profits" such as those "realized or anticipated in highly profitable enterprises or speculative ventures,"[9] and defined the ratepayer/investor balance as follows:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[10]

As such, a fair rate of return is based on the expectation that the utility costs reflect efficient and economical management, and the return will support its credit standing and access to capital, but the return will not be in excess of this level. Utility rates that are consistent with these standards will be just and reasonable, and compensation to the utility will be fair and support financial integrity and credit-standing, under economic management of the utility.

[9] *Bluefield,* 262 U.S. at 692-93.
[10] *Id*. at 693 (emphasis added).

Q PLEASE DESCRIBE THE PROCESS YOU HAVE USED TO ESTIMATE DTE'S COST OF COMMON EQUITY.

A First, I assessed the market's assessment of DTE's risk. Then, I developed a proxy group of publicly-traded utility companies that have similar risks and characteristics to DTE and compared potential differences in risks. I then performed several models based on financial theory to estimate DTE's cost of common equity. These models are: (1) a constant growth Discounted Cash Flow ("DCF") model using consensus analysts' growth rate projections; (2) a constant growth DCF model using sustainable growth rate estimates; (3) a multi-stage growth DCF model; (4) a Risk Premium model; and (5) a Capital Asset Pricing Model ("CAPM").

A DTE's Investment Risk

Q PLEASE DESCRIBE THE MARKET'S ASSESSMENT OF DTE'S INVESTMENT RISK.

A The market's assessment of a company's investment risk is generally described by credit rating analysts' reports. The current credit ratings for DTE are A- and A2, from S&P and Moody's respectively.[11] The Company currently has a "stable" outlook from S&P and a "stable" outlook from Moody's. In its August 2023 report covering DTE, S&P stated as follows:

> Our stable outlook on DTEE reflects our base-case assumption that the company will generate sufficient cash flow to maintain financial measures that support an adjusted FFO-to-debt ratio of 19%-20% through 2024. The stable outlook also reflects our expectation that parent DTE Energy Co. (DTE) will focus growth on its lower-risk, regulated utility strategy. We expect the utility businesses will account for about 90% of the consolidated company. We expect DTE's financial measures will generally remain in line with expectations, including FFO to debt of about 14%-16%.

[11]S&P Capital IQ, accessed on June 21, 2024.

Business Risk

Our assessment of DTEE's stand-alone business risk profile reflects the very low risk of the regulated utility business, operations under a credit-supportive regulatory environment in Michigan, effective management of regulatory risk, and large customer base of 2.3 million customers in Michigan. DTEE benefits from a constructive and supportive regulatory framework in Michigan that supports forward-looking rate cases and various riders that enhance cash flow predictability. In addition, the predominance of residential and commercial customers restricts susceptibility to economic cyclicality and provides more stable operating cash flow. These business strengths are partially offset by its lack of geographic and regulatory diversity with operations focus in southeastern Michigan.

Financial Risk

We assess DTEE's financial measures using our medial volatility table. This reflects the company's regulated electric utility operation and its effective management of regulatory risk in Michigan. Under our base-case scenario, we expect the company's financial measures to remain in the significant range of financial risk profile. Specifically, we expect FFO to debt of about 19%-20% through 2024. Our base-case scenario assumes effective management of regulatory risk through use of the existing constructive regulatory mechanisms in Michigan, capital spending averaging about $3.6 billion annually, dividends averaging about $875 million annually, and continued negative discretionary cash flow primarily driven by robust capital spending. We also expect DTEE will continue to fund its investments in a manner that preserves credit quality.[12]

As noted above, S&P views DTE Electric's credit profile positively, noting its status as a lower-risk, rate-regulated, vertically integrated utility with a supportive regulatory environment in Michigan. The Company effectively manages regulatory risks and benefits from a stable customer base, primarily residential. The recently approved integrated resource plan is seen as credit-supportive, aiding DTE Electric's transition away from coal-fired generation. S&P expects DTE Electric to maintain a stable financial outlook with sufficient cash flow and an adjusted FFO-to-debt ratio of 19%-20% through 2024.

[12]S&P Global Ratings, RatingsDirect, DTE Electric Co., August 18, 2023.

B. DTE's Proposed Capital Structure

Q WHAT IS DTE'S PROPOSED CAPITAL STRUCTURE?

A DTE's proposed capital structure is summarized in Table CCW-6 below:

Table CCW-6

Investor-Supplied Capital Structure

Description	Weight
Debt	50.00%
Common Equity	50.00%
Total	100.00%

Q DO YOU HAVE ANY COMMENTS ON DTE'S PROPOSED CAPITAL STRUCTURE?

A Yes. As I will discuss later, DTE's proposed equity ratio of 53.5% significantly exceeds the equity ratio for the proxy group used to estimate the cost of equity for DTE. As shown on Exhibit AB-5, the proxy group has an average common equity ratio of 40.9% (including short-term debt) and 44.5% (excluding short-term debt).

Q ARE YOU AWARE OF OTHER REGULATORY COMMISSIONS RECOGNIZING THE NEED TO ALIGN THE COST OF EQUITY WITH THE CAPITAL STRUCTURE?

A Yes. In a recent Order, the Arkansas Public Service Commission imputed the capital structure of Southwestern Electric Power Company ("SWEPCO") to be more in-line with the comparable companies used to estimate the cost of equity.[13] The adjustment was to recognize that there must be *congruence* between the cost of equity and the capital structure. Specifically, the Order states as follows:

[13]APSC Docket No. 21-170-U, Doc. No. 323, May 23, 2022, Order No. 14.

> Consistent with our ruling in Order No. 10 of Docket No. 06-101-U, the Commission holds that there should be congruence between the estimated cost of equity and the [debt-to-equity "DTE")] ratio, whereby a lower DTE ratio decreases financial risk and decreases the cost of equity. The evidence of record supports imputing the average capital structure of companies with comparable risk to SWEPCO for the purposes of determining SWEPCO's overall cost of capital.[14]

As I described above, the proxy group has an average common equity ratio of 40.9% (including short-term debt) and 44.5% (excluding short-term debt) as calculated by S&P Global Market Intelligence and *Value Line*, respectively. The Company's proposed equity ratio of 50.00% (excluding short-term debt) exceeds that of the proxy group's comparable equity ratio of 44.5%.

C. Development of Proxy Group

Q PLEASE BRIEFLY DESCRIBE WHY A PROXY GROUP IS NEEDED IN ESTIMATING THE COST OF EQUITY.

A There are a few reasons why a proxy group is needed to estimate the cost of equity. As an initial matter, to be consistent with the *Hope* and *Bluefield* standards, as described above, the allowed return should be commensurate with returns on investments in other firms of comparable risk. A proxy group of similarly situated companies of comparable risk is needed to assess the Company's proposal under this standard.

Even if DTE were a publicly-traded company whose securities could be used to estimate its cost of equity, there exists the potential for certain errors and biases which would make the reliance on a single estimate undesirable and potentially less accurate. A proxy group of comparable risk companies adds reliability to the estimates by

[14] *Id*. at 25.

mitigating the potential for bias that may be introduced by measurement errors of model inputs.

Q PLEASE DESCRIBE HOW YOU IDENTIFIED A PROXY UTILITY GROUP THAT COULD BE USED TO ESTIMATE DTE'S CURRENT MARKET COST OF EQUITY.

A I relied on the same proxy group developed by DTE's witness, Dr. Villadsen.

Q HOW DOES THE INVESTMENT RISK OF DTE COMPARE TO THAT OF THE PROXY GROUP?

A As shown on my Exhibit AB-5, the proxy group has average credit ratings of BBB+ and Baa2 from S&P and Moody's, respectively. The proxy group's average rating of BBB+ from S&P is one notch lower than DTE's rating of A- from S&P. The proxy group's average rating of Baa2 from Moody's is three notches lower than DTE's rating of A2.

As shown on the same exhibit, the proxy group has an average common equity ratio of 40.9% (including short-term debt) and 44.5% (excluding short-term debt) as calculated by S&P Global Market Intelligence and *Value Line*, respectively. DTE's requested common equity ratio of 50.00% (including short-term debt) significantly exceeds the proxy group's equity ratio as described above.

Based on the one and three-notch difference in credit ratings, as well as the difference in equity ratios, the Company's cost of equity capital is most likely to be below the midpoint of the cost of equity range indicated for by the proxy group results.

D. DCF Model

Q PLEASE DESCRIBE THE DCF MODEL.

A The DCF model posits that a stock price equals the sum of the present value of expected future cash flows discounted at the investor's required rate of return or cost of capital. This model is expressed mathematically as follows:

$$P_0 = \frac{D_1}{(1+K)^1} + \frac{D_2}{(1+K)^2} \ldots . \frac{D_\infty}{(1+K)^\infty} \qquad \text{(Equation 1)}$$

P_0 = Current stock price
D = Dividends in periods 1 - ∞
K = Investor's required return

This model can be rearranged in order to estimate the discount rate or investor-required return, known as "K." If it is reasonable to assume that earnings and dividends will grow at a constant rate, then Equation 1 can be rearranged as follows:

$$K = D_1/P_0 + G \qquad \text{(Equation 2)}$$

K = Investor's required return
D_1 = Dividend in first year
P_0 = Current stock price
G = Expected constant dividend growth rate

Equation 2 is referred to as the annual "constant growth" DCF model.

Q PLEASE DESCRIBE THE INPUTS TO YOUR CONSTANT GROWTH DCF MODEL.

A As shown in Equation 2 above, the DCF model requires a current stock price, the expected dividend, and the expected growth rate in dividends.

Q WHAT STOCK PRICE HAVE YOU RELIED ON IN YOUR CONSTANT GROWTH DCF MODEL?

A I relied on the average of the weekly high and low stock prices of the utilities in the proxy group over a 13-week period ending on June 21, 2024. An average stock price

is less susceptible to market price variations than a price at a single point in time. Therefore, an average stock price is less susceptible to aberrant market price movements, which may not reflect the stock's long-term value.

Q WHAT DIVIDEND DID YOU USE IN YOUR CONSTANT GROWTH DCF MODEL?

A I used each proxy company's most recently paid quarterly dividend as reported in *Value Line*.[15] This dividend was annualized (multiplied by 4) and adjusted for next year's growth to produce the D_1 factor for use in Equation 2 above. In other words, I calculate D_1 by multiplying the annualized dividend (D_0) by (1+G).

Q WHAT DIVIDEND GROWTH RATES HAVE YOU USED IN YOUR CONSTANT GROWTH DCF MODEL?

A There are several methods that can be used to estimate the expected growth in dividends. However, regardless of the method, for purposes of determining the market-required return on common equity, one must attempt to estimate investors' expectations about what the dividend, or earnings growth rate, will be, and not what an individual investor or analyst may use to make individual investment decisions.

As predictors of future returns, securities analysts' growth estimates have been shown to be more accurate than growth rates derived from historical data.[16] That is, assuming the market generally makes rational investment decisions, analysts' growth projections are more likely to influence investors' decisions, which are captured in observable stock prices, than growth rates derived only from historical data.

[15] *The Value Line Investment Survey*.

[16] *See*, e.g., David Gordon, Myron Gordon, and Lawrence Gould, Choice Among Methods of Estimating Share Yield, The Journal of Portfolio Management, Spring 1989.

For my constant growth DCF analysis, I have relied on a consensus, or mean, of professional securities analysts' earnings growth estimates as a proxy for investors' dividend growth rate expectations. I used the average of analysts' growth rate estimates from three sources: Zacks, S&P Capital IQ Market Intelligence ("MI"), and Yahoo! Finance. All such projections were available on June 21, 2024, and all were reported online.[17]

Each growth rate projection is based on a survey of independent securities analysts. There is no clear evidence whether a particular analyst is most influential on general market investors. Therefore, a single analyst's projection does not predict investor outlooks as reliably as does a consensus of market analysts' projections. The consensus of estimates is a simple arithmetic average, or mean, of surveyed analysts' earnings growth forecasts. A simple average of the growth forecasts gives equal weight to all surveyed analysts' projections. Therefore, a simple average, or arithmetic mean, of analysts' forecasts is a good proxy for investor expectations.

The growth rates I used in my DCF analysis are shown in Exhibit AB-6. The average growth rate for my proxy group is 6.29% and a median growth rate of 6.29%.

Q WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF MODEL?

A As shown in Exhibit AB-7, page 1, the average and median constant growth DCF returns for my proxy group for the 13-week analysis are 10.43% and 10.51%, respectively.

[17] www.zacks.com; https://finance.yahoo.com; and https://www.capitaliq.spglobal.com/.

Q ARE THERE LIMITATIONS OF THE CONSTANT GROWTH DCF ANALYSIS?

A Yes. The constant growth DCF analysis for my proxy group is based on a group average long-term growth rate of 6.29%. The three- to five-year growth rates are approximately 50% higher than the long-term projected GDP growth rate of 4.24%, described below. As I explain in detail below, a utility's growth rate cannot exceed the growth rate of the economy in which it provides services in perpetuity, which is the time period assumed by the DCF model.

Q HOW DID YOU IDENTIFY THE LONG-TERM PROJECTED GDP GROWTH RATE?

A Although there may be short-term peaks, the long-term sustainable growth rate for a utility stock cannot exceed the growth rate of the economy in which it sells its goods and services. The long-term maximum sustainable growth rate for a utility investment is limited by the projected long-term GDP growth rate, as that reflects the projected long-term growth rate of the economy as a whole. *Blue Chip Financial Forecasts* projects that over the next 5 and 10 years, the U.S. nominal GDP will grow at an annual rate of approximately 4.24%.[18] As such, the average nominal growth rate over the next 10 years is around 4.24%, which I believe is a reasonable proxy of long-term growth.

Later in this testimony, I discuss academic and investment-practitioner support for using the projected long-term GDP growth outlook as a maximum long-term growth rate projection. Using the long-term GDP growth rate as a conservative projection for the maximum growth rate is logical, and is generally consistent with academic and economic-practitioner accepted practices.

[18]Blue Chip Financial Forecast, May 31, 2024 at page 14.

E. Sustainable Growth DCF

Q PLEASE DESCRIBE WHAT THE SUSTAINABLE GROWTH DCF METHOD IS AND HOW YOU ESTIMATED A SUSTAINABLE GROWTH RATE FOR YOUR SUSTAINABLE GROWTH DCF MODEL.

A The sustainable growth rate, also referred to as the internal growth rate, is determined by the proportion of the utility's earnings that is retained and reinvested in its plant and equipment. These reinvested earnings enhance the earnings base, also known as the rate base. The earnings grow as the plant, funded by the reinvested earnings, is put into operation, allowing the utility to receive its authorized return on the additional rate base investment.

The internal growth approach is linked to the percentage of earnings retained within the company, as opposed to being paid out as dividends. The earnings retention ratio is calculated as 1 minus the dividend payout ratio. As the payout ratio decreases, the retention ratio increases, leading to stronger growth as the company funds more investments using retained earnings.

The payout ratios of the proxy group are shown in my Exhibit AB-8. These dividend-payout ratios and earnings-retention ratios then can be used to develop a long-term growth rate driven by earnings retention.

The data used to estimate the long-term sustainable growth rate is based on the Company's current market-to-book ratio and on *Value Line*'s three- to five-year projections of earnings, dividends, earned returns on book equity, and stock issuances.

As shown in Exhibit AB-9, the average and median sustainable growth rates for the proxy group using this internal growth rate model are 5.02% and 4.95%, respectively.

Q WHAT IS THE DCF ESTIMATE USING THESE SUSTAINABLE GROWTH RATES?

A A DCF estimate based on these sustainable growth rates is developed in Exhibit AB-10. As shown there, and using the same formula in Equation 2 above, a sustainable growth DCF analysis produces proxy group average and median DCF results for the 13-week period of 9.10% and 9.03%, respectively.

F. Multi-Stage Growth DCF Model

Q HAVE YOU CONDUCTED ANY OTHER DCF STUDIES?

A Yes. As previously noted, the DCF model is intended to represent the present value of an endless series of future cash flows. Nevertheless, the initial constant growth DCF that I created is based on analyst growth-rate projections, providing a plausible representation of rational investment expectations over the next three-to-five years. The limitation of this constant growth DCF model is that it cannot reflect a reasonable expectation of a shift in growth from a high or low short-term rate to a rate that aligns more with long-term sustainable growth. To accommodate changing growth expectations, I conducted a multi-stage DCF analysis that reflects growth rate change over time.

Q WHY DO YOU BELIEVE GROWTH RATES CAN CHANGE OVER TIME?

A The growth rate projections by analysts for the next three-to-five years are subject to change as the outlook for utility earnings-growth evolves. Utility companies experience fluctuations in their investment cycles. When these companies are undertaking substantial investments, the growth of their rate base accelerates, leading to an increase in earnings growth. However, once a major construction cycle reaches completion or plateaus, the growth in the utility rate base slows down, and its earnings

growth rate declines from an abnormally high three-to-five-year rate, to a lower, sustainable growth rate.

As construction cycles become longer in duration, even with an aggressive construction plan, the growth rate of the utility will naturally slow due to a decrease in rate base growth, as the utility has limited human and capital resources to expand its construction activities. Therefore, the three-to-five-year growth rate projection should be viewed as a long-term sustainable growth rate, but not without considering the current market conditions, industry trends, and determining whether the three-to-five-year growth outlook is feasible and sustainable.

Q PLEASE DESCRIBE YOUR MULTI-STAGE DCF MODEL.

A The multi-stage DCF model reflects the possibility of non-constant growth for a company over time. The multi-stage DCF model reflects three growth periods: (1) a short-term growth period consisting of the first five years; (2) a transition period, consisting of the next five years (6 through 10); and (3) a long-term growth period starting in year 11 and extending into perpetuity.

For the short-term growth period, I relied on the consensus of analysts' growth projections described above in relationship to my constant growth DCF model. For the transition period, the growth rates were reduced or increased by an equal factor reflecting the difference between the analysts' growth rates and the long-term sustainable growth rate. For the long-term growth period, I assumed each company's growth would converge to the maximum sustainable long-term growth rate.

Q WHY IS THE GDP GROWTH PROJECTION A REASONABLE PROXY FOR THE MAXIMUM SUSTAINABLE LONG-TERM GROWTH RATE?

A Utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services. A utilities' earnings and dividend growth is created by increased utility investment in its rate base. Examples of what can drive such investment are: service area economic growth, system reliability upgrades, or state and federal green energy initiatives. As such, nominal GDP growth is a reasonable upper limit for utility sales growth, rate base growth, and earnings growth in the long-run. Therefore, the U.S. GDP nominal growth rate is a conservative proxy for the highest sustainable long-term growth rate of a utility.

Q IS THERE RESEARCH THAT SUPPORTS YOUR POSITION THAT, OVER THE LONG TERM, A COMPANY'S EARNINGS AND DIVIDENDS CANNOT GROW AT A RATE GREATER THAN THE RATE OF GROWTH OF THE U.S. GDP?

A Yes. This concept is supported in published analyst literature and academic work. Specifically, in a textbook titled "Fundamentals of Financial Management," published by Eugene Brigham and Joel F. Houston, the authors state as follows:

> The constant growth model is most appropriate for mature companies with a stable history of growth and stable future expectations. Expected growth rates vary somewhat among companies, but dividends for mature firms are often expected to grow in the future at about the same rate as nominal gross domestic product (real GDP plus inflation).[19]

The use of the economic growth rate is also supported by investment practitioners as outlined as follows:

[19] *Fundamentals of Financial Management*, Eugene F. Brigham and Joel F. Houston, Eleventh Edition 2007, Thomson South-Western, a Division of Thomson Corporation at 298 (emphasis added).

Estimating Growth Rates

> One of the advantages of a three-stage discounted cash flow model is that it fits with life cycle theories in regards to company growth. In these theories, companies are assumed to have a life cycle with varying growth characteristics. Typically, the potential for extraordinary growth in the near term eases over time and eventually growth slows to a more stable level.
>
> * * *
>
> Another approach to estimating long-term growth rates is to focus on estimating the overall economic growth rate. Again, this is the approach used in the *Ibbotson Cost of Capital Yearbook*. To obtain the economic growth rate, a forecast is made of the growth rate's component parts. Expected growth can be broken into two main parts: expected inflation and expected real growth. By analyzing these components separately, it is easier to see the factors that drive growth.[20]

Q HOW DID YOU DETERMINE A LONG-TERM GROWTH RATE THAT REFLECTS THE CURRENT CONSENSUS OF INDEPENDENT MARKET PARTICIPANTS?

A I relied on the consensus of long-term GDP growth projections as projected by independent economists. *Blue Chip Financial Forecasts* publishes the consensus for GDP growth projections twice a year. These projections reflect current outlooks for GDP and are likely to be influential on investors' expectations of future growth outlooks. The consensus of projected GDP growth is about 4.24% over the next 10 years.[21]

Q DO YOU CONSIDER OTHER SOURCES OF PROJECTED LONG-TERM GDP GROWTH?

A Yes, and these alternative sources corroborate the consensus analysts' projections I relied on. Several projections are shown in Table CCW-7 below.

[20]Morningstar, Inc., Ibbotson SBBI 2013 Valuation Yearbook at 51 and 52.
[21]Blue Chip Financial Forecast, May 31, 2024 at page 14.

TABLE CCW-7

GDP Forecasts

Source	Projected Period	Real GDP	Inflation	Nominal GDP
Blue Chip Economic Indicators [1]	5-10 Yrs	2.1%	2.2%	4.2%
EIA - Annual Energy Outlook[2]	27 Yrs	1.9%	2.3%	4.3%
Congressional Budget Office[3]	30 Yrs	1.7%	2.0%	3.8%
Moody's Analytics[4]	31 Yrs	1.9%	2.1%	4.1%
Social Security Administration[5]	76 Yrs	1.6%	2.4%	4.0%
Economist Intelligence Unit[6]	31 Yrs	1.7%	2.2%	4.0%

Sources:
[1]Blue Chip Financial Forecasts, May 31, 2024 at 14.
[2]U.S. EnergyInformation Administration (EIA), Annual Energy Outlook 2023, September, 2022.
[3]Congressional Budget Office, Long-Term Budget Outlook, March 28, 2024.
[4]Moody's Analytics Forecast, last updated March 11, 2024.
[5]Social Security Administration, "2024 OASDI Trustees Report," Table VI.G6. May 6, 2024.
[6]S&P MI, Economist Intelligence Unit, downloaded on April 26, 2024.

As shown in the table above, the real GDP and the inflation fall in the range of 1.6% to 2.1% and 2.0% to 2.4%, respectively. This results in a nominal GDP in the range of 3.8% to 4.3%. Therefore, the nominal GDP growth projections made by these independent sources support my use of 4.24% as a reasonable estimate of market participants' expectations for long-term GDP growth. The real GDP and nominal GDP growth projections made by these independent sources support my use of 4.24% as a reasonable estimate of market participants' expectations for long-term GDP growth.

Q WHAT STOCK PRICE, DIVIDEND, AND GROWTH RATES DID YOU USE IN YOUR MULTI-STAGE DCF ANALYSIS?

A I relied on the same 13-week average stock prices and the most recent quarterly dividend payment data discussed above. For the first stage, I used the consensus of analysts' growth rate projections discussed above in my constant growth DCF model. The first stage covers the first five years, consistent with the time horizon of the securities analysts' growth rate projections. The second stage, or transition stage, begins in year 6 and extends through year 10. The second stage growth transitions the growth rate from the first stage to the third stage using a straight linear trend. For the third stage, or long-term sustainable growth stage, starting in year 11, I used a 4.24% long-term sustainable growth rate based on the consensus of economists' long-term projected nominal GDP growth rate.

Q WHAT ARE THE RESULTS OF YOUR MULTI-STAGE DCF MODEL?

A As shown in Exhibit AB-11, the average and median DCF ROEs for my proxy group using the 13-week average stock price are 8.83% and 8.90%, respectively.

Q PLEASE SUMMARIZE THE RESULTS FROM YOUR DCF ANALYSES.

A The DCF results are summarized in Table CCW-8 below. As described above, the results of the constant growth DCF using analysts' growth rates assume an average long-term growth rate of 6.29%, which is approximately 50% higher than the long-term projected GDP growth rate of 4.24%. This is an unsustainable assumption, and likely leads to an overstatement in the cost of equity for a low-risk regulated utility. As such, it is my opinion that more weight should be given to the sustainable growth and multi-stage models of the DCF.

Table CCW-8

Summary of DCF Results

Description	Proxy Group Mean	Proxy Group Median
Constant Growth DCF Model (Analysts' Growth)	10.43%	10.51%
Constant Growth DCF Model (Sustainable Growth)	9.10%	9.03%
Multi-Stage DCF Model	8.83%	8.90%

G. Risk Premium Model

Q PLEASE DESCRIBE YOUR BOND YIELD PLUS RISK PREMIUM MODEL.

A This model is based on the principle that investors require a higher return to assume greater risk. Common equity investments have greater risk than bonds because bonds have more security of payment in bankruptcy proceedings than common equity and the coupon payments on bonds represent contractual obligations. In contrast, companies are not required to pay dividends or guarantee returns on common equity investments. Therefore, common equity securities are considered to be riskier than bond securities.

This risk premium model is based on two estimates of an equity risk premium. First, I quantify the difference between regulatory commission-authorized returns on common equity and contemporary U.S. Treasury bonds. The difference between the authorized return on common equity and the Treasury bond yield is the risk premium. I estimated the risk premium on an annual basis for each year since January 1986. The authorized ROEs were based on regulatory commission-authorized returns for

utility companies. Authorized returns are typically based on expert witnesses' estimates of the investor-required return at the time of the proceeding.

The second equity risk premium estimate is based on the difference between regulatory commission-authorized returns on common equity and contemporary "A" rated utility bond yields by Moody's. I selected the period 1986 through 2023 because public utility stocks consistently traded at a premium to book value during that period. This is illustrated in Exhibit AB-12, which shows the market-to-book ratio since 1986 for the utility industry was consistently above a multiple of 1.0x. Over this period, an analyst can infer that authorized ROEs were sufficient to support market prices that at least exceeded book value. This is an indication that commission-authorized returns on common equity supported a utility's ability to issue additional common stock without diluting existing shares. It further demonstrates that utilities were able to access equity markets without a detrimental impact on current shareholders.

Based on this analysis, as shown in Exhibit AB-13, the average indicated equity risk premium over U.S. Treasury bond yields has been 5.70%. Since the risk premium can vary depending upon market conditions and changing investor risk perceptions, I believe using an estimated range of risk premiums provides the best method to measure the current return on common equity for a risk premium methodology.

I assessed the five-year and ten-year rolling average risk premiums over the study period to gauge the variability over time of risk premiums. These rolling average risk premiums mitigate the impact of anomalous market conditions and skewed risk premiums over an entire business cycle. As shown on my Exhibit AB-13, the five-year rolling average risk premium over Treasury bonds ranged from 4.25% to 7.09%, while the ten-year rolling average risk premium ranged from 4.38% to 6.91%.

As shown on my Exhibit AB-14, the average indicated equity risk premium over contemporary "A" rated Moody's utility bond yields was 4.34%. The five-year and ten-year rolling average risk premiums ranged from 2.88% to 5.90% and 3.20% to 5.73%, respectively.

Q WHY ARE THE TIME PERIODS USED TO DERIVE THESE EQUITY RISK PREMIUM ESTIMATES APPROPRIATE TO FORM ACCURATE CONCLUSIONS ABOUT CONTEMPORARY MARKET CONDITIONS?

A Contemporary market conditions can change dramatically during the period that rates determined in this proceeding will be in effect. A relatively long period of time where stock valuations reflect premiums to book value indicates that the authorized ROEs and the corresponding equity risk premiums were supportive of investors' return expectations and provided utilities access to the equity markets under reasonable terms and conditions. Further, this time period is long enough to smooth abnormal market movement that might distort equity risk premiums. While market conditions and risk premiums do vary over time, this historical time period is a reasonable period to estimate contemporary risk premiums.

Q PLEASE EXPLAIN OTHER MARKET EVIDENCE YOU RELIED ON IN DETERMINING AN APPROPRIATE EQUITY RISK PREMIUM.

A The equity risk premium should reflect the market's perception of risk in the utility industry today. I have gauged investor perceptions in utility risk today in Exhibit AB-15, where I show the yield-spread between utility bonds and Treasury bonds since 1980. As shown in this schedule, the average utility bond yield-spreads over Treasury

bonds for “A” and “Baa” rated utility bonds for this historical period are 1.48% and 1.90%, respectively.

A current 13-week average “A” rated utility bond yield of 5.71% when compared to the current Treasury bond yield of 4.57%, as shown in Exhibit AB-16, page 1, implies a yield-spread of 1.14%. This current utility bond yield-spread is lower than the long-term average-spread for “A” rated utility bonds of 1.48%. The 13-week average yield on “Baa” rated utility bonds is 5.93%. This indicates a current spread for the “Baa” rated utility bond yield of 1.36%, which is lower than the long-term average of 1.90%.

Q WHAT ARE THE RESULTS BASED ON YOUR RISK PREMIUM ANALYSES?

A I give primary consideration to the Risk Premium results using Treasury bonds and A-rated utility bonds. My recommendation also takes the results of adding the Baa-rated utility bond yield to the equity risk premium over A-rated utility bonds into consideration.

Considering the current and projected economic environment, current yield spreads and equity risk premiums, as well as current levels of interest rates and interest rate projections, a more normalized equity risk premium is warranted. As such, I believe an average equity risk premium over Treasury yields of 5.70% is appropriate. Adding this risk premium to the projected Treasury yield of 4.30% produces an ROE of 10.00%.

Applying a similar methodology as described above, the average of the rolling five-year average risk premiums over A-rated utility bonds is 4.34%. The A-rated utility bond yield has averaged 5.71% over the 13-week period ending June 21, 2024 while the Baa-rated utility bond yield has averaged 5.93% over the same period. Adding this risk premium to the 13-week A-rated utility bond yield of 5.71% produces an estimated

cost of equity of 10.05%. Adding this risk premium to the 13-week Baa-rated utility bond yield of 5.93% produces an estimated cost of equity of 10.27%.

The A-rated utility bond yield has averaged 5.61% over the 26-week period ending June 21, 2024 while the Baa-rated utility bond yield has averaged 5.84% over the same period. Adding the equity risk premium of 4.34% to the 26-week A-rated utility bond yield of 5.61% produces an estimated cost of equity of 9.95%. Adding the equity risk premium of 4.34% to the 26-week Baa-rated utility bond yield of 5.84% produces an estimated cost of equity of 10.18%.

The results of my risk premium analyses are summarized in Table CCW-9.

Table CCW-9

Summary of Risk Premium Results

Description	
Projected Treasury Yield	10.00%
13-Week Yields	
A-Rated Utility Bond	10.05%
Baa-Rated Utility Bond	10.27%
26-Week Yields	
A-Rated Utility Bond	9.95%
Baa-Rated Utility Bond	10.18%

H. Capital Asset Pricing Model ("CAPM")

Q PLEASE DESCRIBE THE CAPM.

A The CAPM method of analysis is based upon the theory that the market-required rate of return for a security is equal to the risk-free rate, plus a risk premium associated with

the specific security. This relationship between risk and return can be expressed mathematically as follows:

$R_i = R_f + B_i \times (R_m - R_f)$ where:

R_i = Required return for stock i
R_f = Risk-free rate
R_m = Expected return for the market portfolio
B_i = Beta - Measure of the risk for stock

The term "beta" in the equation represents the stock-specific risk that cannot be reduced through diversification. In a well-diversified portfolio, specific risks related to individual stocks can be reduced by balancing the portfolio with securities that offset the impact of firm-specific factors, such as business cycle, competition, product mix, and production limitations.

Non-diversifiable risks, on the other hand, are related to market conditions and are referred to as systematic risks. These risks cannot be reduced through diversification and are considered market risks. Conversely, non-systematic risks, also known as business risks, can be reduced through diversification.

According to the CAPM, the market does not compensate investors for taking on risks that can be diversified away. Thus, investors are only compensated for taking on systematic, or non-diversifiable, risks. Beta is a measure of these systematic risks.

Q PLEASE DESCRIBE THE INPUTS TO YOUR CAPM.

A The CAPM requires an estimate of the market risk-free rate, the company's beta, and the market risk premium.

Q WHAT DID YOU USE AS AN ESTIMATE OF THE MARKET RISK-FREE RATE?

A As previously noted, *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield is 4.30%.[22] The current 30-year Treasury bond yield is 4.57%, as shown in Exhibit AB-16 at page 1. I used *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield of 4.30% for my CAPM analysis.

Q WHY DID YOU USE LONG-TERM TREASURY BOND YIELDS AS AN ESTIMATE OF THE RISK-FREE RATE?

A Treasury securities are backed by the full faith and credit of the United States government, so long-term Treasury bonds are considered to have negligible credit risk. Also, long-term Treasury bonds have an investment horizon similar to that of common stock. As a result, investor-anticipated long-run inflation expectations are reflected in both common stock required returns and long-term bond yields. Therefore, the nominal risk-free rate (or expected inflation rate and real risk-free rate) included in a long-term bond yield is a reasonable estimate of the nominal risk-free rate included in common stock returns.

Treasury bond yields, however, do include risk premiums related to future inflation and liquidity. In this regard, a Treasury bond yield is not entirely risk-free. Risk premiums related to unanticipated inflation and interest rates reflect systematic market risks. Consequently, for a company with a beta less than 1.0, using the Treasury bond yield as a proxy for the risk-free rate in the CAPM analysis can produce an overstated estimate of the CAPM return.

[22]Blue Chip Financial Forecast May 31, 2024.

Q WHAT BETA DID YOU USE IN YOUR ANALYSIS?

A As shown in Exhibit AB-17, the current proxy group average and median *Value Line* beta estimates are 0.94 and 0.95, respectively. In my experience, these beta estimates are abnormally high and are unlikely to be sustained over the long-term. As such, I have also reviewed the historical average of the proxy group's *Value Line* betas. The historical average *Value Line* beta since 2014 is 0.78 and has ranged from 0.57 to 0.91. Prior to the recent pandemic, the high end of this range was 0.75.

In addition to *Value Line*, I have also included adjusted beta estimates as provided by Market Intelligence's Beta Generator Model. This model relied on a five-year period on a weekly basis ending June 21, 2024. The average and median Market Intelligence betas are 0.86 and 0.86, respectively. Market Intelligence betas, as calculated using its Beta Generator Model, are adjusted using the Vasicek method and calculated using the S&P 500 as the proxy for the investable market. This is in stark contrast with the *Value Line* beta estimates that are adjusted using a constant weighting of 67%/35% to the raw beta/market beta and use the New York Stock Exchange ("NYSE") as the proxy for the investable market. Because I rely on the S&P 500 to estimate the expected return on the investable market, it makes sense to rely on beta estimates that are calculated using the S&P 500 as the benchmark for the market. Further, as S&P explains:

> The Vasicek Method is a superior alternative to the Bloomberg Beta adjustment. The Bloomberg adjustment is not appropriate for a vast number of situations, as it assigns constant weighting regardless of the standard error in the raw beta estimation (Bloomberg Beta = 1/3*market beta + 2/3*Raw Beta). Given the statistical fact that a larger sample size yields a smaller error, the Vasicek method more appropriately adjusts the raw beta via weights determined by the variance of the individual security versus the variance of a larger sample of comparable companies. The weights are designed to bring the raw beta closer to

whichever beta estimation has the smallest error. This is a feature the Bloomberg beta cannot replicate.[23]

Notably, while S&P makes reference to the Bloomberg method of applying 2/3 and 1/3 weights to the raw beta and market beta, respectively, the comparison still applies to *Value Line's* methodology of applying 67% and 35% weights. Both methods are forms of the Blume adjustment.[24] While the weights are slightly different between the Bloomberg and *Value Line* methods, they are similar and apply a constant weight without any regard to accuracy. As such, the criticisms of the betas offered by S&P apply to both Bloomberg betas and *Value Line* betas.

Q HOW DID YOU DERIVE YOUR MARKET RISK PREMIUM ESTIMATES?

A My market risk premium estimates are derived using two general approaches: a risk premium approach and a DCF approach. I also consider the normalized market risk premium of 5.00% with the normalized risk-free rate of 4.67% as recommended by Kroll, formerly known as Duff & Phelps.[25] Based on this methodology and utilizing a "normalized" risk-free rate of 4.67%, Kroll concludes that the current expected, or forward-looking, market risk premium is 5.00%, implying an expected return on the market of 9.67%.[26]

[23]S&P Market Intelligence, Beta Generator Model.

[24]The Blume adjustment is a tool used to refine a beta measurement in finance. In general, Beta attempts to explain how much a particular investment's price moves compared to the overall market. But beta is often based on historical data, which may not be an accurate method for predicting the future. The Blume adjustment tries to address this by considering the idea that, in the long run, most investments tend to become more similar in their riskiness to the overall market (represented by a beta of 1).

[25]Kroll, and its predecessor Duff & Phelps, is a provider of economic, financial, and valuation data that is often relied on by finance professionals and cited in ROR testimony.

[26]Kroll, *Kroll Increases U.S. Normalized Risk-Free Rate from 3.0% to 3.5%, but Spot 20-Year U.S. Treasury Yield Preferred When Higher*, June 16, 2022. The current 20-year yield of 4.67% exceeds the "normalized" yield of 3.5%. In accordance with Kroll's prescribed method, the greater of the two shall be used under the normalized Kroll methodology, i.e., 4.67%.

Q PLEASE DESCRIBE YOUR MARKET RISK PREMIUM ESTIMATE DERIVED USING THE RISK PREMIUM METHODOLOGY.

A The forward-looking risk premium-based estimate was derived by estimating the expected return on the market (as represented by the S&P 500) and subtracting the risk-free rate from this estimate. I estimated the expected return on the S&P 500 by adding an expected inflation rate to the long-term historical arithmetic average real return on the market. The real return on the market represents the achieved return above the rate of inflation.

The Kroll *SBBI Yearbook* is no longer being published. As such, estimates of the historical, arithmetic-average, real-market return over the period 1926 to 2023 were calculated using data from Morningstar Direct. The arithmetic-average real return on the market since 1926 is 9.02%.[27] A current consensus for projected inflation, as measured by the Consumer Price Index ("CPI"), is 2.40%.[28] Using these estimates, the expected market return is 11.64%.[29] The market risk premium then is the difference between the 11.64% expected market return and the projected risk-free rate of 4.30%, or 7.34%.

Q PLEASE DESCRIBE YOUR MARKET RISK PREMIUM ESTIMATES DERIVED USING THE DCF METHODOLOGY.

A I employed two versions of the constant growth DCF model to develop estimates of the market risk premium. I first employed the Federal Energy Regulatory Commission's ("FERC") method of estimating the expected return on the market that was established in its Opinion No. 569-A. FERC's method for estimating the expected return on the

[27]Morningstar Direct.
[28]Blue Chip Financial Forecast May 31, 2024.
[29][(1 +9.02%) ∗ (1 + 2.40%) - 1] ∗ 100.

market is to perform a constant growth DCF analysis on each of the dividend-paying companies of the S&P 500 index. The growth rate component is based on the average of the growth projections excluding companies with growth rates that were negative or greater than 20%.[30] The weighted average growth rate for the remaining companies is 10.90%. After reflecting the FERC prescribed method of adjusting the dividend yield by (1+ 0.5g), the weighted average expected dividend yield is 1.79%. Thus, the DCF-derived expected return on the market is the sum of those two components, or 12.69%. The market risk premium then is the expected market return of 12.69%, less the projected risk-free rate of 4.30%, or 8.40%.

My second DCF-based market risk premium estimate was derived by performing the same DCF analysis described above, except I used all companies in the S&P 500 index rather than just the dividend-paying companies. The weighted average growth rate for these companies is 11.10%. After reflecting the FERC-prescribed method of adjusting the dividend yield by (1+ 0.5g), the weighted average expected dividend yield is 1.69%. Thus, the DCF-derived expected return on the market is the sum of those two components, or 12.79%. The market risk premium then is the expected market return of 12.79% less the projected risk-free rate of 4.30%, or 8.50%.

The average expected market return based on the DCF model is 12.74% and the average market risk premium based on the two DCF estimates is 8.45%.

[30]Opinion No. 569-A, at 210.

Q HOW DO YOUR EXPECTED MARKET RETURNS COMPARE TO CURRENT EXPECTATIONS OF FINANCIAL INSTITUTIONS?

A As shown in Table CCW-10, my average expected market return of 11.35%[31] exceeds long-term market expectations of several financial institutions.

TABLE CCW-10

Long-Term Expected Return on the Market

Source	Term	Expected Return Large Cap Equities
BlackRock Capital Management[1]	30 Years	7.00%
JP Morgan Chase[2]	10 - 15 Years	7.00%
Vanguard[3]	10 Years	4.2% - 6.2%
Research Affiliates[4]	10 Years	4.00%

Sources:
[1]BlackRock Investment Institute, November 2023 report.
[2]JP Morgan Chase, Long-Term Capital Market Assumptions, 2024 Report.
[3]Vanguard economic and market outlook for 2024: A Return to Sound Money.
[4]Research Affiliates, Asset Allocation Interactive. Retrieved 1/05/2024.

When compared to the expected market returns of financial institutions above, my average expected market return of 11.35% is greater than all of them. For these reasons, my expected market returns, and the associated market risk premiums, should be considered reasonable, if not high-end estimates.

[31]11.35% = (9.67% + 12.74% + 11.64%) / 3.

Q HOW DO YOUR ESTIMATED MARKET RISK PREMIUMS COMPARE TO THAT ESTIMATED BY KROLL?

A The Kroll analysis indicates a market risk premium falls somewhere in the range of 5.00% to 7.17% utilizing data through 2023. My market risk premium estimates are in the range of 5.00% to 8.45%.

Q HOW DOES KROLL MEASURE A MARKET RISK PREMIUM?

A Kroll's range is based on several methodologies. First, Kroll estimated a market risk premium of 7.17% based on the difference between the total market return on common stocks (S&P 500) less the income return on 20-year Treasury bond investments over the 1926-2023 period.[32]

Second, Kroll used the Ibbotson & Chen supply-side model which produced a market risk premium estimate of 6.22%.[33] Kroll explains that the historical market risk premium based on the S&P 500 was influenced by an abnormal expansion of P/E ratios relative to earnings and dividend growth. In order to control for the volatility of extraordinary events and their impacts on P/E ratios, Kroll takes into consideration the three-year average P/E ratio as the current P/E ratio. Therefore, Kroll adjusted this market risk premium estimate to normalize the growth in the P/E ratio to be more in line with the growth in dividends and earnings.

Finally, Kroll developed its own recommended equity, or market risk premium, by employing an analysis that takes into consideration a wide range of economic information, multiple risk premium estimation methodologies, and the current state of the economy by observing measures such as the level of stock indices and corporate

[32]Kroll, *Cost of Capital Navigator*.
[33]*Id*.

spreads as indicators of perceived risk. Based on this methodology, and utilizing a "normalized" risk-free rate of 4.67%, Kroll concludes that the current expected, or forward-looking, market risk premium is 5.00%, implying an expected return on the market of 9.67%.[34]

Q DO YOU HAVE ANY COMMENTS ON THE EXPECTED MARKET RETURNS AND MARKET RISK PREMIUMS DESCRIBED ABOVE?

A Yes. As described above, the average expected market return based on the DCF model is 12.74% and the average market risk premium is 8.45%. The expected market return of 12.74% is based on a constant perpetual growth rate of 11.10%. This is simply unsustainable for the same reasons described in greater detail above.

It simply is not reasonable to believe individual companies can sustain growth rate of 11.10% into perpetuity. In fact, in the CFA curriculum textbooks, the CFA Institute notes as follows with regard to earnings growth rates for companies within the composite indices (i.e., S&P 500):

> Earnings growth for the overall national economy can differ from the growth of earnings per share in a country's equity market composites. This is due to the presence of new businesses that are not yet included in the equity indices and are typically growing at a faster rate than the mature companies that make up the composites. **Thus, the earnings growth rate of companies making up the composites should be lower than the earnings growth rate for the overall economy.**[35]

In addition, a market risk premium in excess of 8.0% is significantly outside the range supported by empirical evidence. For example, Dr. Morin notes in his book,

[34] *Id*.

[35] CFA Program Curriculum, 2014 Level II Vol. 1, "Ethical and Professional Standards, Quantitative Methods, and Economics", Paul Kutasovic, Reading 15 – Economic Growth and the Investment Decision, page 609, footnote 5 (emphasis added).

Modern Regulatory Finance, that several studies of the market risk premium have concluded that a market risk premium in the range of 5.0% to 8.0% is a reasonable estimate for the United States.[36] The Duarte and Rosa study he cites concludes that the historical mean is "quite difficult to improve upon when considering out-of-sample performance measures."[37] Dr. Morin also notes that a survey of professional practices showed that 71% of textbooks/tradebooks used a historical average as the market risk premium, and 60% of financial advisors used a market risk premium in the range of 7.0% to 7.4% (similar to a long-term arithmetic average market risk premium).[38]

Q WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?

A As shown in Exhibit AB-18, I have provided the results of nine different applications of the CAPM. The first three results presented are based on the proxy group's current average *Value Line* beta of 0.94. The results of the CAPM based on these inputs range from 9.38% to 12.27%.

The next set of three results presented are based on the proxy group's historical *Value Line* beta of 0.78. The results of the CAPM based on these inputs range from 8.58% to 10.91%.

The last set of three results presented are based on the proxy group's current S&P Global Market Intelligence beta of 0.86. The results of the CAPM based on these inputs range from 8.99% to 11.60%. My CAPM results are summarized in Table CCW-11.

[36]Dr. Morin references studies by Duarte & Rosa; Professors Ross, Westerfield, and Jordan; Mahera; and Brealey, Myers, and Allen. See *Modern Regulatory Finance*¸ Dr. Roger A. Morin, at pages 190-192. Dr. Morin notes in his textbook that there is a "slight preference" for the upper end of the range (i.e., 8%) during tumultuous times in capital markets with examples being the 2008-2009 credit crisis and the 2020 pandemic.

[37]See *Modern Regulatory Finance*¸ Dr. Roger A. Morin, at page 191, citing the Duarte and Rosa study.

[38]See *Modern Regulatory Finance*¸ Dr. Roger Morin, at page 190, footnote 35.

Because current beta estimates are based on the most recent five years of historical stock returns and volatility, they are being heavily impacted by the market fallout in early 2020 as the global pandemic set in and the market reacted, with this S&P 500 falling more than 40%. For this reason, it is not reasonable to assume current beta estimates, particularly Blume-adjusted betas such as those published by *Value Line*, are reflective of investor expectations at this time which can lead to an overstatement in the estimated cost of equity. As such, I am giving less consideration to the results of my CAPM analyses that rely on current *Value Line* betas. Finally, for the reasons detailed above, I believe it is also reasonable to give less consideration to the CAPM results that rely on market risk premium estimates of 8.45%.

Table CCW-11

CAPM Results Summary

Description	Current VL Beta	Historical VL Beta	Current S&P Beta
Kroll Normalized Method	9.38%	8.58%	8.99%
Risk Premium Method	11.19%	10.01%	10.61%
FERC DCF Method	12.27%	10.91%	11.60%

Q YOU MENTION THAT THE CURRENT 5-YEAR BETA ESTIMATES MIGHT NOT BE REFLECTIVE OF INVESTOR EXPECTATIONS, AND POTENTIALLY OVERSTATE THE COST OF EQUITY. DO YOU HAVE EVIDENCE TO SUPPORT THAT HYPOTHESIS?

A Yes. As mentioned above, all beta estimates calculated over a 5-year historical price period will include the unprecedented volatility and market prices caused by the onset

of the Covid-19 pandemic in early 2020. It is unreasonable to assume that those prices and resulting volatility resemble investor expectations going forward. Prior to the market fallout from the pandemic, utility beta estimates were at several year lows. Subsequent to the period of peak volatility from the pandemic, utility betas have actually declined back toward their normalized levels. This is demonstrated in Table CCW-12 below. In this table, I present the raw unadjusted beta estimates for the 5-year and 3-year period ending June 21, 2024. I then apply Blume adjustment using the same weighting applied by *Value Line*.[39]

[39]The Value Line method to calculated adjusted betas is as follows: $B_{adjusted} = 0.35 + 0.67 \times B_{raw}$

Beta Comparison

Proxy Group	5-Year Beta[1] Unadjusted	5-Year Beta[1] Adjusted[3]	3-Year Beta[2] Unadjusted	3-Year Beta[2] Adjusted[3]
Alliant Energy Corporation	0.81	0.89	0.56	0.72
American Electric Power Company, Inc.	0.77	0.86	0.49	0.68
Ameren Corporation	0.76	0.86	0.54	0.71
Avista Corporation	0.75	0.85	0.45	0.65
Black Hills Corporation	1.04	1.04	0.63	0.77
CMS Energy Corporation	0.76	0.86	0.49	0.68
CenterPoint Energy, Inc.	1.17	1.13	0.61	0.76
Duke Energy Corporation	0.73	0.84	0.42	0.63
Edison International	0.94	0.98	0.69	0.81
Entergy Corporation	0.96	0.99	0.54	0.71
Evergy, Inc.	0.84	0.91	0.53	0.70
Exelon Corporation	0.95	0.99	0.59	0.75
IDACORP, Inc.	0.80	0.88	0.44	0.65
MGE Energy, Inc.	0.56	0.73	0.50	0.69
NextEra Energy, Inc.	0.86	0.93	0.74	0.85
NorthWestern Energy Group, Inc.	0.99	1.02	0.47	0.66
OGE Energy Corp.	1.03	1.04	0.60	0.75
Otter Tail Corporation	0.96	0.99	0.82	0.90
Pinnacle West Capital Corporation	0.90	0.95	0.49	0.68
Public Service Enterprise Group Incorporated	0.93	0.97	0.62	0.77
Sempra	0.90	0.95	0.62	0.76
The Southern Company	0.84	0.92	0.45	0.65
WEC Energy Group, Inc.	0.73	0.84	0.45	0.65
Xcel Energy Inc.	0.74	0.85	0.44	0.65
Average	0.86	0.93	0.55	0.72
Median	0.85	0.92	0.53	0.71

Source:
[1]S&P Global Market Intelligence, betas for the period 6/21/2019 - 6/21/2024.
[2]S&P Global Market Intelligence, betas for the period 6/21/2021 - 6/21/2024.
[3]Adjusted using Value Line's Blume adjustment methodology: 0.35+(0.67 x Unadjusted Beta)

These data clearly demonstrate that systematic market risk has subsided for regulated utilities after controlling for the impacts of the global pandemic and are largely in line with the long-term beta estimates discussed above with average and median beta estimates of 0.72 and 0.71, respectively.

Q WHAT WOULD THE RESULTS OF YOUR CAPM BE UNDER A 3-YEAR BETA?

A Assuming the same risk-free rates and market risk premiums described above, my CAPM results would be in the range of 8.60% to 10.37%, with an average of 9.51%. These results are summarized in Table CCW-13 below.

Table CCW-13

CAPM Analysis Using a 3-Year Beta

Description	3-Year Beta CAPM Results
Kroll Normalized Method	8.60%
Risk Premium Method	9.54%
FERC DCF Method	10.37%
Average	9.51%

Q HAVE YOU CONSIDERED THESE DATA IN YOUR OVERALL RECOMMENDATION?

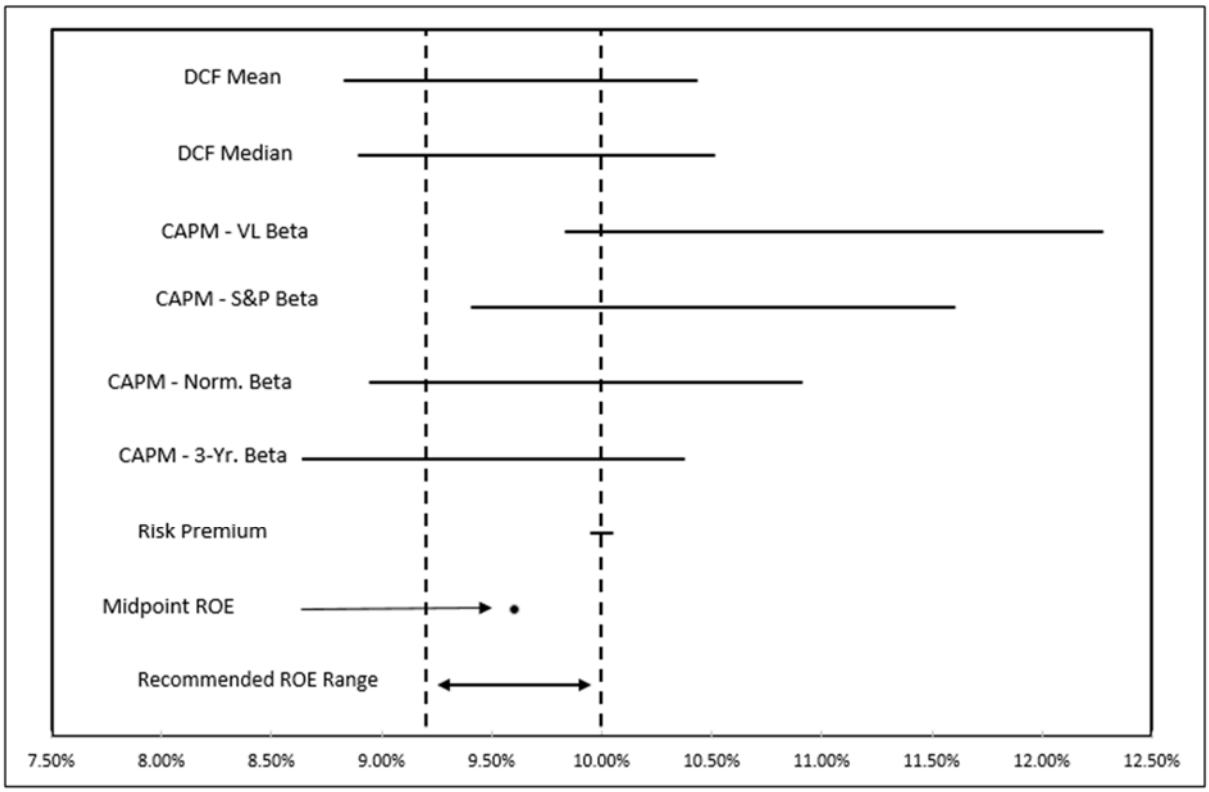
A Yes, I have.

I. Return on Equity Summary

Q BASED ON THE RESULTS OF YOUR RETURN ON COMMON EQUITY ANALYSES DESCRIBED ABOVE, WHAT RETURN ON COMMON EQUITY DO YOU RECOMMEND FOR THE COMPANY?

A The results of my analyses are summarized in Figure CCW-5. In this figure, I present the various measures of central tendency for each of my analytical models.

FIGURE CCW-5



Based on my analyses of the various methodologies described above, I estimate the Company's current market cost of equity to be in the reasonable range of 9.20% to 10.00%. My recommended range takes into consideration the unsustainable growth rates assumed in the constant growth DCF model, the irrational assumption that Value Line's current beta estimates are reflective of current investor expectations, and the unsustainable growth rates assumed in the DCF-derived expected market return for the CAPM. Based on my assessment of DTE's overall risk profile and the results of these analytical methods, I would recommend that this Commission authorize DTE an ROE of 9.60%, which is the midpoint of my recommended range.

V. RESPONSE TO DR. BENTE VILLADSEN

A. Summary of Rebuttal

Q WHAT RETURN ON COMMON EQUITY IS DTE PROPOSING FOR THIS PROCEEDING?

A Dr. Villadsen recommends a ROE based on her market-based model results for her Electric Sample that fall in the range of 10.25% to 11.00%. She concludes that DTE's requested return of 10.50% is conservative "especially so given DTEE's risk profile, which indicates the company has higher business risk than the comparable companies."[40]

Q PLEASE DESCRIBE DR. VILLADSEN'S METHODOLOGY SUPPORTING HER ROE RECOMMENDATION.

A Dr. Villadsen arrived at her estimate using several models that she applied to a sample group of electric and natural gas companies including a traditional CAPM and an empirical CAPM ("ECAPM"), a simple DCF, and a multi-stage growth DCF.[41] Additionally, Dr. Villadsen performed a risk premium model.

Q IS DR. VILLADSEN'S ESTIMATED ROE FOR DTE REASONABLE?

A No. Dr. Villadsen's recommended ROE of 10.50% for DTE is excessive and unreasonable for a low-risk regulated utility company. Further, Dr. Villadsen asserts that DTE's risk is higher than average relative to her electric sample.[42] The unreasonableness of Dr. Villadsen's recommendation is evident from a detailed

[40]Dr. Villadsen Direct at 41.
[41]*Id.*, at 13-14.
[42]*Id.*

assessment of the rate of return models supporting her recommendation in this proceeding.

Q PLEASE SUMMARIZE DR. VILLADSEN'S ROE STUDY RESULTS.

A Dr. Villadsen's ROE study results for her electric sample are summarized in Table CCW-14 below.[43]

As shown in Table CCW-14 above, the model ROE results of Dr. Villadsen's studies applied to her electric sample indicate that the required ROE is in the range of 8.7% to 11.1%. She then increases her market ROE estimate by adjusting her results upward in the range of 0.4% to 1.1% using an overall cost of capital ("OCC") methodology. Dr. Villadsen describes the OCC methodology at pages 12-14 of Appendix B to her testimony. The OCC method employed by Dr. Villadsen is identical to the After-Tax Weighted Average Cost of Capital ("ATWACC") methodology previously rejected by this Commission in previous DTE cases.[44] This ATWACC adjustment increases her recommended range up to 10.25% to 11.0%. Dr. Villadsen asserts this ATWACC adjustment is necessary to properly recognize the difference of DTE's financial risk when applying a market ROE to its book value common equity.

Q DO DR. VILLADSEN'S ROE MODEL RESULTS SUPPORT THE COMPANY'S REQUESTED ROE OF 10.50%, OR EVEN THE ROE RANGE SHE RECOMMENDS?

A No. As described below, Dr. Villadsen's own studies, with reasonable adjustments, would support a ROE of 9.60%.

[43]See generally, Dr. Villadsen's Exhibit A-14, Schedules D5.6 through D5.17.

[44]See U-18014 Order at page 66, and U-18255 Order at page 32. Throughout my response to Dr. Villadsen's testimony, I will use OCC and ATWACC interchangeably.

TABLE CCW-14

Summary of Dr. Villadsen's Sample Results

Model	Model Results	ATWACC Adjustment	Recommended Results
DCF (Electric Sample)			
Simple DCF	10.50%	0.70%	11.20%
Multi-Stage	8.90%	0.50%	9.40%
Average DCF			
CAPM (Electric Sample)			
Traditional CAPM	10.3% - 11.1%	0.60%	10.9% - 11.7%
ECAPM (1.5%)	10.3% - 11.1%	0.90%	11.0% - 11.9%
Traditional CAPM (Hamada)			10.9% - 11.7%
ECAPM (1.5%) (Hamada)			10.8% - 11.7%
Risk Premium (Electric)			10.50%
Range of Electric Results	8.9% - 11.1%		9.4% - 11.7%
Recommended Range			10.25% - 11.0%
Recommended ROE			10.50%

Q PLEASE DESCRIBE THE ISSUES YOU HAVE WITH DR. VILLADSEN'S ANALYSES.

A The issues and concerns I have with Dr. Villadsen's analyses in support of the Company's requested ROE include the following:

1. Her ATWACC adjustment is unnecessary and has previously been rejected by this Commission.

2. More weight should be given to her multi-stage DCF results given the proxy group's growth rate significantly exceeds the projected growth of the US economy.

3. For her CAPM analysis, she includes both an ATWACC adjustment, and alternatively a leveraged beta adjustment to the CAPM results.

4. Her Value Line betas are based on five years of historical stock prices and are significantly being impacted by the spike in volatility as a result of the pandemic and its impact on the market in early 2020. She failed to consider a more normalized estimate of beta.

5. She also relies on an ECAPM analysis and includes adjustments for her ATWACC and leveraged beta methods. In addition to my concerns for these two adjustments, Dr. Villadsen's ECAPM analysis is miscalculated because she uses adjusted betas within an ECAPM format. This is inappropriate because an adjusted beta accomplishes the same thing as an ECAPM analysis. Both levelize the security market line in measuring a fair ROE based on a given level of systematic risk or beta risk. Her ECAPM analysis double counts the increase in the CAPM return estimates for companies with betas less than 1, which reflects her proxy group and DTE in this case.

6. Dr. Villadsen's assertion that DTE is of higher risk than her sample companies is incomplete, inaccurate, and should be ignored.

B. ATWACC

Q PLEASE DESCRIBE DR. VILLADSEN'S PROPOSED ATWACC ROE ADJUSTMENT.

A Dr. Villadsen calculates an ATWACC for each of her sample DCF and CAPM results by using each sample company's market value capital structure and assumes cost rates for the cost of debt and preferred stock based on each company's credit rating. She also assumes DTE's composite tax rate of 25.7% is applicable to all companies in her sample. Once she calculates the OCC or ATWACC, she then backs into the ROE required to produce the same rate of return using DTE's book value capital structure and embedded cost of debt.

These ATWACC adjustments to her ROE estimates are discussed in her Appendix B and developed in the workpapers accompanying her schedules for the CAPM and DCF return estimates.

Q DO YOU BELIEVE THAT THE ATWACC METHODOLOGY IS REASONABLE POLICY FOR SETTING AN APPROVED ROE IN THE UNITED STATES?

A An obvious concern is that DTE Electric's common stock is not publicly traded and does not have a market value capital structure. The ATWACC methodology is poor regulatory policy and should be rejected for several reasons:

1. It does not produce clear and transparent objectives for management to use that will accomplish the objective of minimizing its overall rate of return while preserving its financial integrity. It ignores a utility's need for capital discipline, treating it as it would an unregulated utility affiliate. Therefore, a regulatory commission cannot oversee the reasonableness and prudence of management decisions in managing its capital structure. Under the ATWACC theory, management's decisions to manage its capital structure can be skewed by changes in market value which change the market value capitalization mix. Management simply has no control over the market value capital structure, but it does have control over the book value capital structure. As such, setting the rate of return and measuring risk based on book value capital structure creates a more transparent and clear path for regulatory oversight of management's effort to maintain a balanced and reasonable capital structure.

2. The ATWACC introduces significant additional instability and unreliability into the utility's cost of service and tariff rates. Book value capital structure weights permit the utility to hedge or lock-in a large portion of capital market costs in arriving at the rate of return used to set rates. This rate of return cost hedge stabilizes the utility's cost of service, which in turn helps stabilize utility rates. A stable method of setting rates also allows investors to more accurately assess the future earnings and cash flow outlooks for the utility, which will reduce the business risk of the utility. The ATWACC, on the other hand, will produce an overall rate of return which will change based on both changes to market value capital structure weights and also based on changes to market capital costs. Hence, a major component of the cost structure of the utility (i.e., the overall rate of return) will vary based on market forces from rate case to rate case. This rate of return variability will introduce significant instability in the utility's cost of service (via rate of return changes) and hence instability in tariff rates. Introducing additional instability and unreliability in the utility's cost structure and rates will not benefit either investors or ratepayers.

3. The ATWACC artificially increases rates to produce an excessive ROE opportunity for utility investors, as if the utility were an unregulated affiliate. Inflating a utility's rates to provide this excessive earnings opportunity is unjust and unreasonable to ratepayers and should be rejected.

Q IS THE ATWACC METHODOLOGY PROPOSED BY DR. VILLADSEN COMMONLY ACCEPTED IN ELECTRIC RATE-SETTING PROCEEDINGS IN THE UNITED STATES, OR MICHIGAN?

A No. Importantly, this Commission has rejected the application of the ATWACC methodology in U-18014, stating:

> "[…] the Commission does agree with the PFD that little or no weight should be given to the utility's ATWACC calculations."[45]

The Commission reaffirmed its rejection of the ATWACC methodology in Case No. U-18255.[46]

In a recent Nicor Gas rate case (Docket No. 21-0098), the Illinois Commerce Commission explicitly rejected the application of any leverage ROE adjustments, stating the following in regard to Dr. Villadsen's leverage adjustments:

> Additionally, the Company's leverage adjustments improperly inflated the Company's ROE recommendation, especially for the water companies. Further, the leverage adjustments are based on the flawed argument that a market-derived ROE does not produce a fair rate of return when applied to a book value rate base. In the Commission's view, an ROE derived from market-based models should be applied to the book value common equity ratio of the Illinois utility because the book value capital structure reflects the amount of capital a utility actually uses to finance the acquisition of assets for providing utility service, which are included in rate base. In contrast, market value typically includes appreciated value, which is not used in establishing the overall or weighted average cost of capital in ratemaking proceedings for Illinois utilities. The Commission has used this approach to establish utility rates for decades and the results have consistently provided Illinois utilities with adequate access to capital at reasonable costs. In contrast, allowing upward adjustments to the allowed ROE to reflect leverage adjustments would result in a never-ending upward movement in the allowed rate of return, which would not properly balance the interests of customers and the utility.
>
> * * *

[45]Michigan Public Service Commission, Case No. U-18014, Final Order, page 66, January 31, 2017.

[46]Michigan Public Service Commission, Case No. U-18255, Final Order, page 32, April 18, 2018.

> The Commission concludes that the Company's ROE recommendations should not be adopted primarily because the Company's DCF and CAPM estimates include leverage adjustments, which the Commission has routinely rejected.[47]

Therefore, the ATWACC methodology is a flawed approach that is not supported by regulatory commissions and should be rejected.

C. Dr. Villadsen's DCF Analysis

Q PLEASE DESCRIBE DR. VILLADSEN'S DCF ANALYSIS.

A Dr. Villadsen develops two versions of the DCF model, a quarterly constant growth DCF and a multi-stage DCF. After she removes what she has deemed to be low-end outliers, her constant growth DCF model for her electric group is based on an average growth rate of 6.24% and produces an average of 10.5% for the electric sample.[48] Her multi-stage DCF method is similar to mine and assumes a terminal growth rate of 4.0% based on the projected growth of the US economy. After she removes what she has deemed to be low-end outliers, her multi-stage DCF result is 8.9% for her electric sample.[49]

Q WHAT CONCERNS DO YOU HAVE WITH DR. VILLADSEN'S DCF ANALYSIS?

A In addition to the inclusion of her financial leverage adjustments, I am concerned with her arbitrary exclusions of low-end outliers without removing high-end outliers. While I agree that the Otter Tail results should be removed, as it has a negative growth rate, she should not have excluded Entergy from her simple DCF results, nor should she

[47]Illinois Commerce Commission, Docket No. 21-0098, *Northern Illinois Gas Company d/b/a Nicor Gas Company*, Final Order at 93-94, November 18, 2021.

[48]Exhibit A-14, Schedules D5.6 and D5.7. From her simple DCF, she excludes the DCF results of Entergy Corp. and Otter Tail Corp.

[49]In addition to Entergy and Otter Tail, Dr. Villadsen also excludes the result for MGE Energy from her multi-stage analysis.

have excluded MGE Energy from her multi-stage DCF in addition to Entergy's results. It is hard to grasp how Dr. Villadsen can reasonably exclude positive results from Entergy or MGE Energy for being too low when she includes results as high as 16.7% for OGE Energy.[50]

I also have concern that her recommendation places too much weight on the results of her constant growth DCF analysis and not nearly enough weight on her multi-stage DCF results. As I explain above, her electric sample's average growth rate projection is 6.24%, and is assumed in perpetuity in her constant growth model. This growth rate exceeds her projected growth rate of 4.24% of the US economy by 47%. A more reasonable estimate for the DCF analysis would be the median of her unadjusted results, excluding Otter Tail, of 8.7% (multi-stage DCF) and 10.15% (constant growth DCF), or 9.4%.

D. Dr. Villadsen's CAPM Analysis

Q PLEASE DESCRIBE DR. VILLADSEN'S CAPM ANALYSIS.

A Dr. Villadsen develops two versions of the CAPM model, a traditional CAPM and an ECAPM. In her analyses, Dr. Villadsen relied upon two different scenarios. In the first scenario, she used a projected risk-free rate of 4.30% with a market risk premium of 7.17%. In this scenario, Dr. Villadsen's risk-free rate is based on the projected 10-year Treasury yield of 3.80%, plus an adjustment for term to maturity of 0.50%, for a projected 20-year risk-free rate of 4.30%. In the second scenario, she used the same forecasted yield of 4.30% and a market risk premium of 6.37%. Applying these inputs

[50]Exhibit A-14, Schedules D5.6 and D5.7.

with her *Value Line* betas, she produces her bare-bones CAPM estimates of 11.1% and 10.3% for her electric sample.[51]

To these bare bones or "base" CAPM returns, Dr. Villadsen proposes either one of two ROE adjustments. First, she proposes to add to her base CAPM return estimate an ATWACC ROE adjustment of approximately 60 basis points. This produces an ATWACC-adjusted CAPM return for her electric sample in the range of 10.9% to 11.7%.[52] For the reasons outlined above, this ATWACC adjustment should be rejected.

Alternatively, Dr. Villadsen proposes a financial risk adjustment to reflect a leveraged beta adjustment. This leveraged beta adjustment adds approximately 60 basis points to the base CAPM return estimates.[53] This leverage adjustment to the base CAPM return estimate produces an excessive and unreasonable ROE for DTE.

Q WHAT CONCERNS DO YOU HAVE WITH DR. VILLADSEN'S CAPM ANALYSIS?

A In addition to her various leverage adjustments, my concerns are that her Value Line betas are still being impacted by the market fallout caused by the pandemic in early 2020 and are not reflective of current investor expectations. As described above with regard to my own CAPM analysis, I have demonstrated that betas, after removing the impact of the pandemic, are much lower than betas based on five years of historical prices and volatility. Based on these data presented in Table CCW-12, it cannot be reasonably argued that the market risk of utility stocks, as measured by beta, has gradually increased over the last several years.

[51]Exhibit A-14, Schedule D5.10.
[52]Villadsen Schedule D5.12
[53]Villadsen Schedule D5.15

Q WHAT CONCERNS DO YOU HAVE WITH DR. VILLADSEN'S VALUE LINE BETA ESTIMATES?

A As I explain above in regard to my own CAPM analysis, these beta estimates are abnormally high and are unlikely to be sustained over the long-term. As such, I believe it to be reasonable to consider the historical average of the proxy group's *Value Line* betas. The historical average *Value Line* beta since 2014 is 0.78 and has ranged from 0.57 to 0.91.[54] Prior to the recent pandemic, the high end of this range was 0.75. Further, after removing the effects of the global pandemic from beta, the most recent 3-year beta estimates are 0.72 on average for the proxy group.

Q WHAT CONCERNS DO YOU HAVE WITH DR. VILLADSEN'S PROJECTED TREASURY YIELD OF 4.30%?

A As I describe above, Dr. Villadsen's projected risk free rate of 4.30% is based on a projected 10-year Treasury yield of 3.80% plus a 0.50% spread to account for the differences between the 20-year yield over the 10-year yield. More recent projections for the 10-year Treasury yield are 4.0% while the most recent projection for the 30-year yield is 4.3%. In other words, Dr. Villadsen assumes that the 20-year yield will be equal to the 30-year yield. Such an assumption is unreasonable and should be rejected. A more reasonable estimate of the projected 20-year Treasury yield would be somewhere between the projected yields for the 10-year Treasury (4.0%) and the 30-year Treasury (4.3%). The midpoint of these projections is 4.15%.

[54] Exhibit AB-17.

Q WHAT WOULD DR. VILLADSEN'S CAPM RESULTS BE AFTER ACCOUNTING FOR THESE CHANGES?

A As explained in detail above, the market risk of utility stocks has declined subsequent to the market fallout as a result of the global pandemic. As such, betas based on five years of prices and volatility overstate the cost of equity in a CAPM analysis. A more reasonable estimate of beta based on prices and volatility after the peak impact of the pandemic must be considered. As explained above, the average beta for the proxy group based on Value Line's methodology using three years of prices and volatility is 0.72.[55] Simply incorporating this beta in her analysis reduces her CAPM results to 9.46% under the scenario with her 7.17% market risk premium, or 8.89% under the scenario with her 6.37% market risk premium.[56]

Q PLEASE EXPLAIN DR. VILLADSEN'S LEVERAGED BETA ADJUSTMENT.

A As an alternative to her ATWACC adjustment to her CAPM results, Dr. Villadsen measures an additional ROE adjustment based on leveraged adjustments to the beta component of the CAPM study. In producing this adjustment, she applies the Hamada method to de-lever and re-lever the beta component in both the CAPM and the ECAPM with and without the effect of income taxes.[57]

Applying the Hamada formula increases the electric sample *Value Line* beta from 0.88 to 1.04 (without and with taxes) for the electric sample.[58] The Hamada model produces CAPM results in the range of 10.9% to 11.7% and ECAPM results in the range of 10.8% to 11.7% for the electric sample.[59]

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[55]Table CCW-13.
[56]0.72 x 7.17% + 4.30% = 9.46%; 0.72 x 6.37% + 4.30% = 8.89%
[57]Villadsen Direct at Appendix B; Exhibit A-14, Schedule D5.14.
[58]Exhibit A-14, Schedule D5.15.
[59]*Id*.

Q IS DR. VILLADSEN'S APPLICATION OF THE LEVERAGED BETA ADJUSTMENT REASONABLE?

A No. As described above, Dr. Villadsen's financial leverage adjustments are generally not accepted in establishing a fair ROE in regulated rate-setting proceedings such as this one.

Q DO YOU HAVE ANY CONCERNS WITH DR. VILLADSEN'S ECAPM RETURN ESTIMATES?

A Yes. I also have concerns with Dr. Villadsen's reliance on her ECAPM return estimates. Specifically, Dr. Villadsen included an adjusted beta within her ECAPM studies.[60] This adjustment is inconsistent with the academic research supporting the development of an ECAPM methodology.[61] Bottom line, using adjusted betas within an ECAPM study double counts the purpose of the ECAPM study – that is, to flatten the security market line and increase a CAPM return estimate for companies with betas less than 1, and decrease the CAPM return estimate for betas greater than 1.

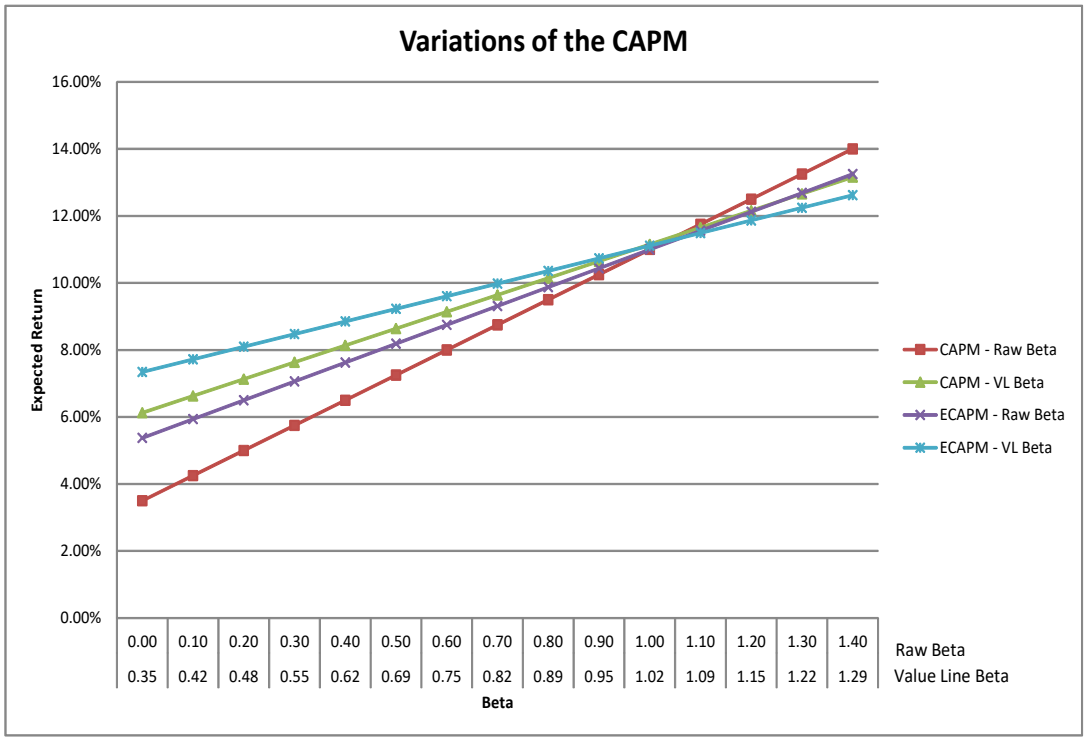
Dr. Villadsen discusses the objective of the ECAPM at pages 32-33 of her testimony. As shown in Dr. Villadsen's Figure 8, the ECAPM will raise the intercept point of the security market line and flatten the slope. Again, this has the effect of increasing CAPM return estimates for companies with betas less than 1, and decreasing the CAPM return estimates for companies with betas greater than 1. Importantly, however, the use of an adjusted beta such as those published by *Value Line*, produces comparable adjustments to the security market line and CAPM return

[60]Villadsen Schedule D5.10.

[61]See Black, Fischer, "Beta and Return," *The Journal of Portfolio Management,* Fall 1993, 8-18; and Black, Fischer, Michael C. Jensen and Myron Scholes, "The Capital Asset Pricing Model: Some Empirical Tests," 1972.

estimate. In effect, using an adjusted beta within an ECAPM study has the effect of a double adjustment to the slope and intercept of the security market line. This is illustrated in my Figure CCW-6 below.

FIGURE CCW-6



Assumptions:
Market Risk Premium is 7.50%
Risk-Free Rate is 3.50%

As shown in Figure CCW-6 above, the CAPM using a *Value Line* beta, versus a CAPM using a raw beta shows that the *Value Line* beta raises the intercept slope and flattens the security market line. Further, the ECAPM using a raw beta, and an ECAPM using a *Value Line* beta, have a magnified effect of increasing the intercept slope and further flattening the security market line.

There is simply no legitimate basis to use an adjusted beta within an ECAPM because they are designed to produce the same effect on the CAPM return estimate.

E. Dr. Villadsen's Risk Premium Analysis

Q PLEASE DESCRIBE DR. VILLADSEN'S RISK PREMIUM ANALYSES.

A Dr. Villadsen's risk premium analyses are predicated on an inverse relationship between authorized ROEs for vertically integrated electric utilities and long-term Treasury yields during the period 1990 through 2023 using a regression analysis.[62] In her analysis, she uses the resulting regression formula to predict a risk premium based on the same forecasted long-term Treasury yield of 4.05% she used in her CAPM analyses and electric utility ROE decisions. This regression formula and her forecasted Treasury yield of 4.05% produced an estimated risk premium of approximately 6.3%, which resulted in a ROE of 10.4%.[63]

Q DO YOU HAVE ANY OBSERVATIONS REGARDING DR. VILLADSEN'S RISK PREMIUM ANALYSIS THAT YOU WOULD LIKE TO POINT OUT?

A I believe her projected risk-free rate and projected risk premium are both too high. As I describe above, Dr. Villadsen's projected risk-free rate of 4.30% is based on a projected 10-year Treasury yield of 3.80% plus a 0.50% spread to account for the differences between the 20-year yield over the 10-year yield. More recent projections for the 10-year Treasury yield are 4.0%, while the most recent projection for the 30-year yield is 4.3%. As explained above, a more reasonable assumption is for the 20-year yield to be the midpoint between the project 10-year and 30-year yields, or 4.15%. In addition, as discussed above, the authorized ROE equity risk premium has been average or below recently. Assuming an equity risk premium significantly above average as Dr. Villadsen has done is irrational. Assuming an average equity risk

[62]Exhibit A-14, Schedule D5.16.
[63]*Id*.

premium and more recent estimates of Treasury bond yields produces a cost of equity estimate of 10.0%.

F. Conclusion that DTE is of Higher Risk

Q DID DR. VILLADSEN OFFER AN ASSESSMENT OF DTE'S RISK RELATIVE TO HER ELECTRIC SAMPLE?

A Yes. Beginning on page 41 of her testimony, Dr. Villadsen offers a few examples of why she believes DTE is of higher business risk relative to her sample companies. Dr. Villadsen's examples including the lack of a decoupling mechanism, DTE's ownership of the Fermi 2 Nuclear Generating Plant, DTE's heavy reliance on coal-based generation, and the Company's capital expenditure program.

Q DO YOU BELIEVE DR. VILLADSEN ACCURATELY ASSESSED THE RISK OF DTE RELATIVE TO THE SAMPLE?

A No. In short, Dr. Villadsen has cherry-picked risks potentially faced by DTE without considering other unique risks faced by the proxy group companies. Dr. Villadsen's concerns about these particular risks should be ignored. Dr. Villadsen overlooks the fact that DTE's S&P rating of A- is higher than that of the proxy group even though she presents the data in her Figure 7. Importantly, the proxy group's rating from Moody's is 3 notches lower than DTE Electric's rating from Moody's, while the proxy group's BBB+ rating from S&P is one notch lower than that of DTE Electric's. Based on these objective data alone, Dr. Villadsen cannot legitimately argue that DTE Electric is of higher risk.

First, to the extent ratings agencies deemed these particular risks detrimental to DTE, ratings agencies would have taken them into consideration and they would be

reflected in DTE's credit ratings. As I discussed above in detail, and show on my Exhibit AB-5, DTE's ratings from both S&P and Moody's are higher than those of the proxy group. S&P and other credit rating agencies go through great detail in assessing a utility's business risk and financial risk in order to evaluate their assessment of its total investment risk. If anything, DTE's total risk is less than that of the proxy group, not more. Dr. Villadsen's argument that DTE is of higher risk is misleading and should be ignored.

Second, as I described above concerning the CAPM, investors are not compensated for taking on company-specific risks, as those risks can be eliminated through portfolio diversification. Institutional investors are the largest holders of utility stocks in general. Examples of institutional investors include, but are not limited to, pension funds, endowments, and mutual funds. Even if one were to accept Dr. Villadsen's misleading assertion that DTE is of higher risk, to suggest these investors are not well-diversified and somehow need to be compensated for taking on company-specific risks would be in error and violate the CAPM.

Based on the above, Dr. Villadsen's conclusion that DTE is of higher risk relative to her sample companies is unfounded and should be rejected.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Christopher C. Walters

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Christopher C. Walters. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A I received a Bachelor of Science Degree in Business Economics and Finance from Southern Illinois University Edwardsville. I have also received a Master of Business Administration Degree from Lindenwood University.

As a Principal at BAI, I perform detailed technical analyses and research to support regulatory projects including expert testimony covering various regulatory issues. Since my career at BAI began in 2011, I have held the positions of Analyst, Associate Consultant, Consultant, Senior Consultant, and Associate. Throughout my tenure, I have been involved with several regulated projects for electric, natural gas and water and wastewater utilities, as well as competitive procurement of electric power and gas supply. My regulatory project work includes estimating the cost of equity capital, capital structure evaluations, assessing financial integrity, merger and acquisition related issues, risk management related issues, depreciation rate studies, and other revenue requirement issues.

BAI was formed in April 1995. BAI and its predecessor firm have participated in more than 700 regulatory proceedings in 40 states and Canada.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

Q HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A Yes. I have sponsored testimony before state regulatory commissions including: Arizona, Arkansas, Colorado, Delaware, Florida, Georgia, Illinois, Iowa, Kansas, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, South Carolina, Texas, Utah, and Wyoming. In addition, I have also sponsored testimony before the City Council of New Orleans and an affidavit before the FERC.

Q PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.

A I earned the Chartered Financial Analyst (“CFA”) designation from the CFA Institute. The CFA charter was awarded after successfully completing three examinations which

covered the subject areas of financial accounting and reporting analysis, corporate finance, economics, fixed income and equity valuation, derivatives, alternative investments, risk management, and professional and ethical conduct. I am a member of the CFA Institute and the CFA Society of St. Louis.

502345

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**

Rebuttal Testimony of

Christopher C. Walters

On behalf of

Association of Businesses Advocating Tariff Equity

August 16, 2024

BRUBAKER & ASSOCIATES, INC.

Project 11638

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**

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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**

Rebuttal Testimony of Christopher C. Walters

I. Introduction

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Christopher C. Walters. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q ARE YOU THE SAME CHRISTOPHER C. WALTERS WHO PREVIOUSLY FILED DIRECT TESTIMONY ON JULY 26, 2024 ON BEHALF OF ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY ("ABATE")?

A Yes, I am.

Q WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A In my rebuttal testimony, I respond to the rate of return ("ROR") recommendation put forward by Michigan Public Service Commission Staff ("Staff") witness Mr. Joseph Ufolla. In particular, I respond to Mr. Ufolla's recommended ROE of 9.90%.

My silence on any particular issue raised in the direct testimony of Staff or other interveners should not be construed as tacit agreement.

II. Response to Mr. Ufolla

Q WHAT OVERALL ROR IS STAFF PROPOSING DTE BE ALLOWED IN THIS PROCEEDING?

A Through the testimony of its witness, Mr. Ufolla, Staff recommends DTE be allowed an overall ROR of 5.66%. Staff's recommended ROR is headlined by an allowed ROE of 9.90% and an investor-supplied capital structure that includes a 50.0% common equity ratio.[1]

Q DO YOU HAVE ANY CONCERNS WITH MR. UFOLLA'S ANALYSIS?

A Yes. My primary concern with Mr. Ufolla's recommended ROR lies with his recommendation that DTE's allowed ROE be set at 9.90%.

Q PLEASE SUMMARIZE THE ANALYTICAL METHODS MR. UFOLLA RELIES ON IN SUPPORT OF HIS RECOMMENDED ROE.

A Mr. Ufolla performed a DCF analysis and a traditional CAPM on a proxy group of eight natural gas utility holding companies, and three iterations of a Risk Premium model. He also observed the average authorized ROE for electric utilities in 2023 and 2024. Based on these data, Mr. Ufolla opines that DTE's cost of equity is within a range of 9.30% to 10.30%. His recommended ROE of 9.90% is above the midpoint of this range. The high-end of Mr. Ufolla's recommended range appears to be based on the results of his proxy group's average and median CAPM results of 10.23% and 10.31%, respectively. The low-end of his range appears to be supported by his Risk Premium

[1]Direct testimony of Joseph Ufolla at 4.

model results, which fall in the range of 8.63% to 9.66%. His DCF results fall between his CAPM and Risk Premium results.[2]

Q WHAT CONCERNS DO YOU HAVE WITH MR. UFOLLA'S ROE ANALYSIS?

A My main concerns with Mr. Ufolla's ROE analyses are as follows: (1) Mr. Ufolla's recommended ROE is unexplainably at the high-end of his recommended range of 9.30% to 10.30%; (2) Mr. Ufolla's ROE recommendation is inconsistent with his recommendation in DTE's pending gas rate case (U-21291), and; (3) Mr. Ufolla's CAPM analysis is overstated because it is based on five-year betas that are not representative of current market conditions, perceived risk of regulated utilities, or investor expectations.[3] Absent these flaws, the high-end of Mr. Ufolla's range would be significantly lower than 10.3%.

Q WHY DO YOU BELIEVE MR. UFOLLA'S RECOMMENDATIONS IN THIS CASE ARE INCONSISTENT WITH HIS RECOMMENDATIONS IN DTE'S PENDING GAS RATE CASE, U-21291?

A In that case, Mr. Ufolla has the same recommended range of 9.3% to 10.3%.[4] Yet, in that case, Mr. Ufolla recommended DTE Gas be awarded an ROE of 9.8%, which is the midpoint of his recommended range. Unexplainably, Mr. Ufolla recommends DTE Electric be authorized an ROE of 9.9% in this case despite having the same recommended range and despite DTE Gas and DTE Electric both currently having the same ROE of 9.9% currently authorized.[5] There is no reason for DTE Electric's ROE

[2] *Id.* at 21.
[3] Staff Exhibit S-4, Schedule D-5, page 4.
[4] MPSC Case No. U-21291, Direct Testimony of Joseph Ufolla at 24.
[5] Direct testimony of Joseph Ufolla at 21.

be set in the upper-half of Mr. Ufolla's range. As I explain throughout this testimony, Mr. Ufolla's recommended range is overstated.

Q WHY DO YOU BELIEVE MR. UFOLLA'S RECOMMENDED RANGE IS OVERSTATED?

A The high-end of Mr. Ufolla's range (10.30%) is based on the results of his CAPM analysis which range from 10.23% to 10.31%.[6] As I explained in my direct testimony, current Value Line beta estimates, which are used in Mr. Ufolla's CAPM, are based on five years of historical prices and volatility. This means that Value Line's betas are being heavily impacted by the market fallout as a result of the onset of a global pandemic in early 2020. As such, betas based on five years of data are not representative of investor expectations, current market conditions, or perceived market risk of regulated utility companies. As shown on Mr. Ufolla's Exhibit S-4, Schedule D-5, his average proxy group beta is 0.94, and ranges from 0.80 to 1.15. It is simply unrealistic to assume that utilities are approximately as risky as the market, on average. As I demonstrated in my direct testimony, when measuring betas after removing the impact of the global pandemic, utility betas are approximately 0.72 under Value Line's adjustment methodology.[7] This level of beta is in-line with their long-term averages.

Q WHAT WOULD MR. UFOLLA'S CAPM RESULTS LOOK LIKE USING A BETA OF 0.72 INSTEAD OF THE BIASED ESTIMATE OF 0.94 HE RELIED ON?

A Assuming Mr. Ufolla's risk-free rate of 3.85% and market risk premium of 6.80%, his CAPM results would be lowered from 10.23% to 8.75%. Giving each of those results

[6] *Id*.
[7] Direct testimony of Christopher Walters at 54-57.

equal weight, the midpoint of 10.23% and 8.75% is 9.37%, or nearly 100 basis points lower than Mr. Ufolla's recommended high-end of 10.30%.

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the Application of 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**

Rebuttal Testimony and Exhibits of

Brian C. Andrews

On behalf of

Association of Businesses Advocating Tariff Equity

August 16, 2024

BRUBAKER & ASSOCIATES, INC.

Project 11638

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**

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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**

Rebuttal Testimony of Brian C. Andrews

I. Introduction

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Andrews. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Association of Businesses Advocating Tariff Equity ("ABATE"). ABATE consists of large usage customers that purchase substantial amounts of electric power and/or delivery service from DTE Electric Company ("DTE"

or "Company"). They primarily take service under DTE Rider D8, Rate D11, Rider 3 and/or Rider 10.

Q WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A My Rebuttal Testimony responds to Michigan Public Service Commission Staff ("Staff") witness Mark J. Pung's testimony. Specifically, I will respond to his proposal to change the allocation of DTE's purchased capacity costs

Q PLEASE BRIEFLY SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS IN THIS PROCEEDING.

A My conclusions and recommendations are as follows:

1. I recommend that Staff witness Mr. Pung's proposal to allocate DTE's purchased capacity costs using the 75-0-25 Production Cost Allocator be rejected.

2. DTE's purchased capacity costs are largely related to renewable energy assets (wind, solar, and biomass) that were required for compliance with PA 295. These costs are largely fixed costs, and the majority of these costs are already allocated on the basis of energy.

3. DTE's proposal for $138 million of these costs to be allocated using 4 Coincident Peak ("4CP") demands should be approved.

4. Staff's proposal would inappropriately shift $4.5 million out of the Residential classes, with the Primary classes receiving $4.1 million.

5. DTE's renewable energy assets are largely fixed costs. They have no fuel cost and low Operation and Maintenance ("O&M"). DTE's Federal Energy Regulatory Commission ("FERC") Form 1 data shows that just 11% of its costs for renewable energy assets are variable and 89% of the costs are fixed.

6. Due to the process by which renewable assets are included in rates, DTE allocates about 60% of these costs on the basis of energy and 40% of the costs on the basis of demand.

7. The Michigan Public Service Commission ("Commission") should reject Staff witness Mr. Pung's proposal to allocator purchased capacity costs using the 75-0-25 allocator, and instead approve DTE's proposal to allocate these costs solely on the basis of 4CP demands.

II. Rebuttal to Staff Witness Pung

Q WHAT IS MR. PUNG'S PROPOSAL FOR THE ALLOCATION OF PURCHASED CAPACITY COSTS?

A Mr. Pung disagrees with the Company's position that purchased capacity costs should be allocated using allocator 251, which is based on the 4CP (coincident peak), 100% demand but excluding the R10 rate class. Instead, he proposes that purchased capacity costs be allocated using the 4CP 75-0-25 allocator.[1]

Q WHAT IS THE IMPACT OF MR. PUNG'S PROPOSAL TO ALLOCATE PURCHASED CAPACITY COSTS USING THE 4CP 75-0-25 ALLOCATOR?

A I have updated DTE's Class Cost of Service Study ("CCOSS") model to incorporate only this change. The results are shown in Table 1 below.

Table 1

Impact of Changing the Allocation of Purchased Capacity

Group	DTE Proposed Revenue Requirement ($000)	Revenue Requirement with Purchased Capacity Allocated with 75-0-25 Allocator ($000)	Change ($000)
Residential	$ 1,435,793	$ 1,431,252	$ (4,540)
Secondary	$ 814,280	$ 814,484	$ 205
Primary	$ 951,851	$ 955,996	$ 4,145
Lighting	$ 11,253	$ 11,444	$ 190
Total	**$ 3,213,177**	**$ 3,213,177**	**$ (0)**

[1]Direct Testimony of Mark J. Pung at page 11, line 3 through page 12, line 4.

As can be seen, this proposal would shift $4.5 million out of the Residential classes, with the Primary classes picking up $4.1 million, Secondary and Lighting each would receive approximately $0.2 million.

Q WHAT ARE DTE'S PURCHASED CAPACITY COSTS IN THIS PROCEEDING?

A In Table 2 below, I show DTE's $138.1 million of purchased capacity costs by group.

Table 2

DTE's Purchased Capacity Costs

PURPA/PA2 Contracts	$ 8,892
PA295/342 Renewable - Company Owned	$ 95,126
PA295/342 Renewable - PPA Wind	$ 30,503
PA295/342 Renewable - PPA LFG/Biomass	$ 4,840
Capacity Purchases	$ (1,308)
Total 2025 Purchased Capacity Costs	**$ 138,054**

Source: Exhibit A-26, Schedule P3

As shown above, the vast majority (95%) of these costs are related to renewable facilities required under PA 295. DTE's owned renewable assets comprise 69% of the total. The Public Utility Regulatory Policies Act ("PURPA") contracts and other renewable Purchased Power Agreements ("PPA") make up the rest, along with a small offset for DTE's capacity sales.

Q DO THE VALUES IN TABLE 2 REFLECT THE ENTIRE COST OF THE PA 295 ASSETS?

A No. Table 2 only shows what DTE has determined to be the capacity related portion of these assets, which is based on the fixed priced component of the transfer price at

the time the assets were approved. In total, the PA 295 assets have a cost of $388.3 million. DTE has separated these costs into "fuel related"[2] and "capacity-related" buckets in its Exhibit AB-26, Schedule P2. DTE~~'s~~ shows that $130.4 million is capacity-related and $257.9 million is "fuel-related."

Q UNDER DTE'S POSITION HOW ARE THE $388.3 MILLION OF PA 295 COSTS ALLOCATED?

A The $130.4 million deemed capacity-related is allocated using Allocator 251 which is 100% 4CP demands, excluding the R10 class. The $257.9 million of "fuel-related" PA 295 assets costs is allocated using allocator ~~192~~111, which is ~~90~~100% energy, ~~10% 4CP demands,~~ excluding the R10 class. ~~In my Exhibit AB-22, I have determined that~~ Therefore, 6~~0~~0% of these costs are allocated on the basis of energy and ~~40~~34% are allocated on the basis of 4CP demands under DTE's proposal. Under Staff's proposal to allocate the capacity-related portion with the 4CP 75-0-25, the amount allocated on energy would increase to approximately ~~68~~75%, and demand would decrease to ~~32~~25%.[3]

Q ARE DTE'S COSTS FOR ITS OWNED RENEWABLE FACILITIES LARGELY FIXED?

A Yes. According to data compiled by S&P, from DTE's FERC Form 1 filings, DTE reports that roughly 89% of the costs of its renewable assets (wind, biomass, and solar) are fixed. With just 11% being variable. See Exhibit AB-23. This clearly makes sense.

[2]With the exception of biomass plants, these assets would have no fuel costs as they are wind and solar resources. Fuel-related is the nomenclature used by DTE, and is simply the portion of the asset cost that has not been deemed to be capacity-related based on the fixed-cost proportion of the transfer prices.

[3]Demand-related portion would be $130.47 million x 75% ~~+ 257.862 million x 10%~~ = $~~123.638~~97.85 million or ~~32~~25% of 388.332 million. Energy portion would then be 1-~~32~~25% = ~~68~~75%.

Wind and solar assets have no fuel costs. The majority of the costs of these assets are incurred when they are installed, with little variable production expense. That is, regardless of customer energy consumption, or even energy generation of DTE's facilities, 89% of the costs would remain fixed.

Q DOES IT MAKE SENSE TO ALLOCATE THE CAPACITY-RELATED PORTION OF THE PA 295 RENEWABLE ASSETS USING THE 4CP 75-0-25 ALLOCATOR?

A No. As I have demonstrated, DTE's PA 295 renewable resources are largely fixed costs assets, and 6~~0~~% of the costs of these assets are already allocated on the basis of energy. The 4CP 75-0-25 allocator might be appropriate for these costs if the entirety of them were allocated in the same manner, as with DTE's traditional production resources. That simply is not the case with the PA 295 renewable resource costs. If Staff's proposal were to be adopted, then ~~68~~75% of the costs of the PA 295 renewable resource costs would be allocated on the basis of energy; despite as much as 89% of these costs being fixed costs. Since DTE's owned facilities represent the majority of the purchased capacity costs, the bulk of the purchased capacity costs would be unchanged, regardless of energy production or customer usage. Therefore, no additional energy allocation should be approved, and the currently approved methodology should remain in effect. The current methodology already over-allocates on the basis of energy because the majority of the purchased capacity costs are related to DTE's owned renewable generation facilities. If the Commission is to make any modification to the allocation of DTE's PA 295 renewable assets, it should allocate them more on the basis of demand than is currently approved and in the opposite direction of Staff's proposal.

Q HOW SHOULD DTE'S PURCHASED CAPACITY COSTS BE ALLOCATED?

A DTE'S purchased capacity costs should continue to be allocated using the 100% 4CP allocator, specifically, DTE's allocator 251.

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A Yes, it does.

Qualifications of Brian C. Andrews

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Andrews. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A I received a Bachelor of Science Degree in Electrical Engineering from the Washington University in St. Louis/University of Missouri - St. Louis Joint Engineering Program. I have also received a Master of Science Degree in Applied Economics from Georgia Southern University.

I have attended training seminars on multiple topics including class cost of service, depreciation, power risk analysis, production cost modeling, cost-estimation for transmission projects, transmission line routing, MISO load serving entity fundamentals and more.

I am a member and a former President of the Society of Depreciation Professionals. I have been awarded the designation of Certified Depreciation Professional ("CDP") by the Society of Depreciation Professionals. I am also a certified Engineer Intern in the State of Missouri.

As an Associate at BAI, and as a Senior Consultant, Consultant, Associate Consultant and Assistant Engineer before that, I have been involved with several

regulated and competitive electric service issues. These have included book depreciation, fuel and purchased power cost, transmission planning, transmission line routing, resource planning including renewable portfolio standards compliance, electric price forecasting, class cost of service, power procurement, and rate design. This has involved use of power flow, production cost, cost of service, and various other analyses and models to address these issues, utilizing, but not limited to, various programs such as Strategist, RealTime, PSS/E, MatLab, R Studio, ArcGIS, Excel, and the United States Department of Energy/Bonneville Power Administration's Corona and Field Effects ("CAFÉ") Program. In addition, I have received extensive training on the PLEXOS Integrated Energy Model and the EnCompass Power Planning Software. I have provided testimony on many of these issues before the Public Service Commissions in Arizona, Arkansas, California, Colorado, Florida, Illinois, Indiana, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Missouri, Montana, New Mexico, Oklahoma, South Carolina, Texas, and Washington DC.

BAI was formed in April 1995. BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

JUDGE WALLACE: Is that it for you, Mr. Campbell?

MR. CAMPBELL: Yes, your Honor. Thank you.

JUDGE WALLACE: Thank you. All right. Is there anybody else that wanted to bind in right now?

O.K. Let's go ahead and take a break until 10:30, and then is that going to be O.K., Ms. Durian, for Ms. Braunschweig?

MS. DURIAN: Yes, your Honor.

JUDGE WALLACE: O.K. So let's all be back here at 10:30 and finish up here. Let's see. 10:30, that gets us to 11:30-ish. Lori, what is -- off the record.

(Recess from 10:13 a.m. until 10:32 a.m.)

JUDGE WALLACE: We're back on the record in Case No. U-1534. Ms. Durian, please call your witness.

MS. DURIAN: The Staff calls Elaina M. Braunschweig to the witness stand.

- - -

E L A I N A M. B R A U N S C H W E I G

was called as a witness on behalf of Michigan Public Service Commission Staff and, having been duly sworn to testify the truth, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. DURIAN:

Q Please state your name and business address for the record.

A My name is Elaina M. Braunschweig, and my business address is 7109 West Saginaw Highway, Lansing, Michigan 48917.

Q Witness Braunschweig, did you prepare or cause to be prepared and prefiled a document consisting of a cover sheet, Qualifications and Direct Testimony of Elaina M. Braunschweig, comprised of 18 pages of questions and answers, dated July 26, 2024?

A Yes, I did.

Q Do you have any changes to your direct testimony today?

A No, I do not.

Q If asked the questions in your direct testimony today, would your answers be the same?

A Yes, they would.

Q Did you prepare or cause to be prepared and prefiled Exhibits A-17.0, S-17.1, and S-17.2, as it relates to your direct testimony?

A Yes, I did.

Q Do you have any changes to your exhibits today?

A No, I do not.

Q Witness Braunschweig, did you prepare or cause to be

prepared and prefiled a document consisting of a cover sheet and Rebuttal Testimony of Elaina M. Braunschweig, comprised of ten pages of questions and answers, dated August 26, 2024?

A Yes, I did.

Q Excuse me. Dated August --

A August 16. Sorry.

Q Is it correct that it was dated August 16, 2024?

A Yes.

Q If I asked the questions in your rebuttal testimony today, would your answers be the same?

A Yes.

MS. DURIAN: Staff moves for the binding in of the Direct and Rebuttal Testimony of Witness Elaina M. Braunschweig, Staff also moves for the admission of the witness exhibits at the close of cross-examination. The Staff tenders Witness Braunschweig for cross-examination.

JUDGE WALLACE: Thank you, Ms. Durian. Is there any objection to binding in the direct and rebuttal testimony of Ms. Braunschweig?

Hearing none, the testimony is bound in.

Is there any objection to the admission of Exhibits S-17.0, S-17.1, and S-17.2?

Hearing none, those exhibits are

admitted.

(Testimony Bound In.)

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S T A T E OF M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*** * * ***

In the matter on 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**

QUALIFICATIONS AND DIRECT TESTIMONY OF

ELAINA M. BRAUNSCHWEIG

MICHIGAN PUBLIC SERVICE COMMISSION

July 26, 2024

QUALIFICATIONS OF ELAINA M. BRAUNSCHWEIG
CASE NUMBER U-21534
PART I

Q. Please state your name and business address.

A. My name is Elaina M. Braunschweig. Pronouns she/her, but preferably "witness Braunschweig" in place of pronouns and titles. My business address is 7109 West Saginaw Hwy, Lansing, Michigan 48917.

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

A. I am employed by the Michigan Public Service Commission (MPSC or Commission) as a Departmental Analyst for the Rates and Tariff Section of the Regulated Energy Division.

Q. Please describe your educational background.

A. In 2018, I completed my Bachelor of Arts dual-major in Economics & Management and German with a minor in International Studies with honors from Albion College.

Q. What are your current responsibilities at the MPSC?

A. As an analyst, I participate in rate and tariff amendment under the direct supervision of the Rates and Tariff manager. I am also responsible for coordinating tariff-related *ex-parte* cases and updating the gas and electric bill comparison spreadsheets for the MPSC website. In the middle of 2020, I began liaising with the MPSC Customer Assistance Division on low-income programs and have since specialized in low-income matters. I handle the section's connection to low-income energy assistance and affordability. In July 2021, I began co-leading the Affordability, Alignment, and Assistance subcommittee in the Commission's Energy Affordability and Accessibility Collaborative and continue that to-date.

QUALIFICATIONS OF ELAINA M. BRAUNSCHWEIG
CASE NUMBER U-21534
PART I

Q. Have you attended any seminars or other training courses relating to your current role?

A. Yes. In August 2021, I participated in Michigan State University's Institute of Public Utilities Annual Regulatory Studies Program Fundamentals Course. In October 2021, I attended Michigan State University's Institute of Public Utilities Advanced Cost Allocation and Rate Design Course, and in February 2022, I attended EUCI's Electric Utility Pricing Trends in Cost Recovery Course.

Q. Have you previously presented testimony or participated in utility cases before the MPSC?

A. Yes, I have presented testimony or otherwise participated in the following cases:

MPSC Case	Company	Description
U-20650	Consumers Energy—Gas	Rate Design/Low-Income
U-20757	Commission	Low-Income Covid Report
U-20907	UMERC	Budget Billing Revisions
U-20929	DTE Energy	PSP Pilot Proposal
U-21021	Consumers Energy	PIPP Pilot Proposal
U-21148	Consumers Energy—Gas	Rate Design/Low-Income
U-20836	DTE Energy	Low-Income Credits
U-21286	UPPCO	Low-Income Credits
U-21308	Consumers Energy—Gas	Rate Design/Low-Income
U-21461	Indiana Michigan Power	Rate Design/Low-Income
U-21490	Consumers Energy—Gas	Low-Income Credits
U-21291	DTE Gas	Low-Income Credits

DIRECT TESTIMONY OF ELAINA M. BRAUNSCHWEIG
CASE NUMBER U-21534
PART II

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Staff's position on DTE Electric Company's (the Company) Low Income Assistance Credit (LIA) credit increase proposal, Residential Income Assistance Credit (RIA) customer count projection, and Residential Service Senior Citizen Provision (RSC) customer count projection.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

Exhibit No. S-17.0, titled "DTE's Audit Response"

Exhibit No. S-17.1, titled "Residential Income Assistance and Residential Senior Citizen Credit Projection Support"

Exhibit No. S-17.2, titled "Affordability, Alignment, and Assistance Subcommittee 12/4/2023"

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

A. Yes, they were.

Q. How is your testimony structured?

A. My testimony is structured as follows:

1. Company Low Income Assistance Credit (LIA) Proposal
2. LIA Counterproposal
3. LIA Tariff Proposals
4. Company RIA Projection
5. Staff RIA Projection
6. Company RSC Projection

7. Staff RSC Projection

8. Summary

1. Company Low Income Assistance Credit (LIA) Proposal

Q. Please summarize the Company's LIA-related testimony to which you will be responding.

A. Company witness Jason E. Sparks' testimony focuses primarily on justifying the energy assistance options the Company currently offers. Company witness Sparks states that the Company's current Payment Stability Plan (PSP)[1] pilot data will be presented to the Commission's Energy Affordability and Accessibility Collaborative (EAAC) in 2024, in line with Commission directives.[2] Company witness Sparks proposes to increase the LIA credit from $40/month to $50/month,[3] stating that at the inception of the LIA credit in U-17767, the credit would have credited approximately 43% of an eligible customer's bill, however, the LIA would only credit approximately 34% of an eligible customer's bill under the Company's most recently approved rates (in MPSC Case No. U-21297).[4] To have the LIA credit amount cover a similar proportion as when it was originally proposed, the credit would need to be $50/month, according to Company witness Sparks.[5] Company witness Sparks therefore proposes increasing the LIA from $40/month to $50/month in the instant case.[6]

[1] The PSP is the Company's percentage of income payment plan (PIPP).
[2] Company witness Sparks, Direct Testimony, pg. 14.
[3] Company witness Sparks, Direct Testimony, pg. 19.
[4] *Id.*
[5] *Id.*
[6] *Id.*

Q. Do you support this proposal for Commission approval?

A. No, I recommend this proposal be rejected for the reasons I discuss later in my testimony.

2. LIA Counterproposal

Q. What Commission decisions are relevant to discussion of energy assistance proposals?

A. As directed in the DTE Electric rate case order in MPSC Case No. U-20836, the Commission charged the EAAC with reviewing a report detailing LIA enrollment and to discuss the LIA enrollment assignment and enrollment cap, followed by submitting a report and recommendations to the Commission.[7] In the December 21, 2023 Order in MPSC Case No. U-20757, the Commission reaffirmed its interest in the EAAC's analysis of utilities' Residential Income Assistance Credit/Low Income Assistance Credit[8] as fulfillment of MCL 460.11(2) and directed Staff to include analysis of PIPPs and Michigan Energy Assistance Program (MEAP) offerings to assist the Commission in understanding current energy assistance offerings.[9]

Q. Based on the cited Commission orders, what is your reaction to the Company's position?

A. My position is that Michigan's most vulnerable customers would benefit from additional assistance, but I am not persuaded that Company witness Sparks

[7] MPSC Case No. U-20836, 11/18/22 Order, p. 407.
[8] Abbreviated to RIA/LIA
[9] MPSC Case No. U-20757, 12/21/23 Order, pp. 14-15.

provides the comprehensive analysis and diverse, collaborative input the Commission is looking for to inform utility energy assistance changes. As indicated by the cited orders, this collaborative RIA/LIA reform work is being performed in the EAAC workgroups. Staff's position is that collaborative discussions with interested/invested parties as well as all investor-owned utilities will lead to the most informed positions and decisions on this matter.

I will not be responding to Company witness Sparks' claimed best use-case of the RIA nor LIA credits nor their effectiveness, but that does not indicate my agreement with those claims nor other related Company policy and procedures, since it is my position that these matters are appropriately being addressed elsewhere at the Commission's direction.

Q. Has the EAAC completed the directives in the Commission orders discussed previously?

A. Not completely. The Affordability, Alignment, and Assistance subcommittee (AAA) of the EAAC has already outlined three options to replace or modify the current RIA and LIA credits, including cost estimates based on utilities that complied with the AAA data requests. This information can more specifically be found summarized in the December 5, 2023 meeting PowerPoint presentation[10] in which Staff synthesized data submitted by the utilities.[11]

[10] Exhibit No. S-17.2. Slide title formatting was modified from the original presentation to add exhibit information, however, the content of the PowerPoint was not changed.

[11] The AAA also has materials that will provide much more in-depth detail outlining the reform options, but Staff is not submitting that as evidence at this time due to its premature nature, since the goal of Staff's testimony in the instant case is not to propose those reform options to the Commission. The PowerPoint serves as evidence that RIA/LIA reform discussions and analysis are underway.

Similar to Company witness Sparks' proposal, the second option discussed in the AAA included tying a single credit which would increase proportionally with rates.[12] Staff appreciates Company witness Sparks' ideas and analysis and can consider them in its RIA/LIA reform proposals in the AAA.

Q. Do representatives from the Company or its affiliates participate in the AAA subcommittee?

A. Yes.

Q. Has the AAA submitted the previously discussed proposal and analysis to the Commission yet?

A. No, the report has not yet been submitted because the PIPP pilots are not yet complete and, as Company witness Sparks noted, have not been presented to the EAAC for analysis. Once the EAAC receives this analysis later this year, the EAAC can move forward with completing its Commission directives.

Staff's preliminary admission of EAAC materials in the instant case aims only to demonstrate to the Commission that proposals similar to Company witness Sparks' proposal are being examined in the EAAC. Staff's aim is not to propose any of the EAAC's RIA/LIA reforms for approval in the instant case, as they have not yet been fully examined.

Q. Could the timeline for the AAA report conflict with the statutory deadlines in the current rate case?

[12] Exhibit No. S-17.2, pp. 13, 15, 17.

A. Yes, the legislatively required 10-month date for a Commission decision in the instant case is approximately January 28, 2025. Currently the AAA subcommittee is targeting a deadline for DTE to submit its PIPP analysis by the end of this year, with a MPSC Staff response to the PIPP report as well as a resolution to the LIA/energy assistance analysis targeted to be sometime in the first quarter of 2025.

Q. What is Staff's recommendation in the instant case?

A. Since work is underway to reform the RIA and LIA credits, as demonstrated by the above discussion and evidence, Staff recommends the Commission not approve any changes to the structure of the credits and instead leave this issue to the EAAC until it completes its relevant Commission directives.

Q. How did Staff incorporate this recommendation in its case?

A. Staff witness David W. Isakson updated Staff's proposed LIA credit amount on Schedule F-3 across all applicable residential rate schedules to remain at $40, consistent with Staff's recommendation.

3. LIA Tariff Proposals

Q. Do you have any recommendations relating to the LIA tariff on all proposed residential tariff sheets?

A. Yes. Whether the Commission rejects or accepts my LIA credit amount recommendation, the credit amount outlined in the tariff should reflect the Commission's decision.

Additionally, whether or not the Commission approves the migration of LIA customers from rate D1.6 to all residential rate schedules, as recommended by

Staff witness David W. Isakson and Company witness Aaron Willis, the LIA language should be updated to reflect the language currently approved by the Commission and used by other regulated utilities. Staff's proposed language should accurately reflect the eligibility requirements already employed by the Company and defined in MCL 460.10 (t), which is the statute that defines the eligibility of customers receiving this form of assistance.

Q. What tariff language is Staff proposing edits to?

A. "SPECIAL LOW INCOME ASSISTANCE (LIA) CREDIT: To qualify for this credit a customer must provide annual evidence of receiving a Home Heating Credit (HHC) energy draft or warrant, or must provide confirmation by an authorized State or Federal agency verifying that the customer's total household income does not exceed 150% of the poverty level as published by the United States department of health and human services or if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid. This credit shall be limited to an annual average of 32,000 customers. This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) or the Senior Citizen Provision Delivery Charges: The Special Low Income Assistance Credit is $(50.00) per customer per month and is applicable to Full Service and Retail Open Access customers."

Q. What is Staff proposing as the new language?

A. "Low Income Assistance Credit Pilot
This credit is available to up to an annual average of 32,000 qualifying customers taking service under an applicable residential rate schedule. This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) or the Senior Citizen Provision.
In addition to the income verification methods listed above, a customer may qualify for the Low Income Assistance Credit Pilot with proof of Enrollment in the Company's affordable payment plan as sanctioned under the Michigan Energy Assistance Program (MEAP) or having received one-time MEAP assistance in the past 12 months.
The monthly credit for the residential Low Income Assistance Credit shall be applied as follows: Income Assistance Credit: $(40.00) per meter per month.
If a credit balance occurs, the credit shall apply to the customer's future utility charges."

Q. Why is this language preferrable to the Company-proposed language?

A. The above language is preferrable because it more succinctly defines eligibility by using the RIA eligibility ("income verification methods listed above") instead of listing out eligibility criteria, and it should reflect the current enrollment practices more accurately (the Company largely pairs the LIA with affordable payment plan recipients). Additionally, it is best to clarify that the 32,000 enrollment cap is across all residential rate schedules and not for each individual rate schedule on which this language will appear.

4. Company RIA Projection

Q. What monthly RIA credit disbursement figure did the Company propose recovery of in the instant case?

A. The Company included recovery of 83,000 monthly RIA credits in the test year.[13]

Q. Did the Company provide support for its calculation or basis for the projection in its initial filing?

A. No, it did not.

Q. Does Staff support this projection?

A. No, it does not. When Staff inquired through audit requests, the Company provided its explanation for its projection, but failed to provide the calculation when requested.[14] According to the Company's response, the RIA projection is based on average historical RIA percent increases. However, as is shown in the

[13] Direct testimony of Company witness Jason E. Sparks, p. 16.
[14] Exhibit No. S-17.0

exhibit detailing the response, the percent increases have been very inconsistent and there seems to be no pattern in the percentage increase in RIA enrollments. The Company did not explain why this projection method was used when Staff asked.

5. Staff RIA Projection

Q. What RIA credit disbursement projection does Staff support for recovery in rates?

A. Staff supports using a 3-year historical average monthly credit disbursement number of 56,134, which has a corresponding revenue adjustment of $2,740,321, as detailed in Exhibit No. S-17.1.

Q. In developing your RIA projection, why did you not include the enrollment data from 2023 that was provided on page 16 of Company witness Sparks' testimony?

A. I did not include the data because Company witness Sparks indicated in testimony that the customer counts he used were from billing period end of month snapshots instead of monthly averages, as is used in Part III Attachment 5(9). If you compare the data on page 16 of Company witness Sparks' testimony to data reported in Part III Attachment 5(9), you will see the reported enrollment numbers are different. Staff does not support using data as of a single point in time on which to base the RIA projections, rather being in favor of monthly/annual averages. The Commission has denied the use of single point in time data in developing the RIA projection in MPSC Case No. U-21389, which Staff cites later in testimony.

Q. Why is this projection method more reasonable than the Company's?

A. It is more reasonable because the projection normalizes for enrollment fluctuations caused by one of the main contributors to RIA enrollments: the Low Income Home Energy Assistance Program, as I will describe.

Q. What are the main qualifiers for RIA recipients?

A. The main identifiers for RIA eligibility and thus automatic enrollment into this program are: the Michigan Department of Health and Human Services (MDHHS), the Michigan Department of Treasury, or Michigan Energy Assistance Program (MEAP) grantees notifying utilities of a customer receiving a State Emergency Relief (SER) payment, a Home Heating Credit (HHC) energy draft, or one-time assistance payment, respectively, that would get applied to their account. These programs require the utilities to apply a payment to the customer's account on the program manager's behalf, which identify the customer as RIA-qualified, as per MCL 460.11 (2) and defined in MCL 460.10(t).

Q. What impacts RIA credit enrollment fluctuations?

A. SER and HHC are funded by the Low-Income Home Energy Assistance Program (LIHEAP); MDHHS could also allocate LIHEAP SER dollars to other programs such as Energy Direct one-time payments (however, this program seems to have come to an end). Since all but MEAP are funded by federal LIHEAP dollars, the main determinant of RIA enrollment fluctuation is average LIHEAP funding levels.

Q. What are the historical funding levels for MEAP?

A. MEAP was established through Public Act 615 of 2012 and is funded at $50,000,000 annually per Public Act 95 of 2013.

Q. What are the historical LIHEAP funding levels for Michigan?

A. Please see the chart below.

Historical Michigan LIHEAP Funding		
Fiscal Year	**Funding Level**	**Monthly RIA Enrollments (fiscal years)[15]**
October 1, 2019-September 30, 2020	$ 197,960,572.00	39,013
October 1, 2020-September 30, 2021	$ 435,542,243.25	54,773
October 1, 2021-September 30, 2022	$ 166,875,852.32	65,521
October 1, 2022-September 30, 2023	$ 269,598,865.00	77,107*
October 1, 2023-September 30, 2024	$ 161,019,682	
Company TY		83,000

*from page 16 of the direct testimony of Company witness Jason E. Sparks. Mostly based on month-end snapshots instead of monthly averages

Q. Please further explain how average LIHEAP funding levels are the main determinant of RIA enrollment fluctuation.

A. I specify average funding levels because year-to-year LIHEAP funding levels change. How MDHHS allocates LIHEAP dollars and how much assistance each customer receives will influence the number of RIA-eligible LIHEAP recipients. This will create trends in the RIA enrollment, but RIA enrollment will not necessarily increase proportional to the LIHEAP funding level. Especially if the

[15] Exhibit No. S-17.1

United States Congress passes bills that allocate additional LIHEAP funding to each state that may not be required to be spent within the fiscal year like normal LIHEAP allocations are. For example, fiscal years 2021[16] and 2023[17] included additional Covid-related funding that has since been exhausted. The increase in RIA enrollment from 2021 to 2022, however, was partly due to an increase in SER as well as four rounds of LIHEAP Direct Support (now called Energy Direct) payments in 2022 and 2023.[18]

Q. Is the elevated RIA enrollment from Covid-19 related funding and LIHEAP Energy Direct in 2022-2023 expected to carry over into the test year?

A. No, it is not. Since RIA customer eligibility is re-verified annually,[19] the higher number of recipients the Company reported in 2022 and 2023 should not be automatically rolled over into the test year, meaning RIA enrollments should slowly decrease in the absence of the elevated Covid-related funding.

Q. What relevant RIA projection has been accepted by the Commission in recent rate cases?

A. In Consumers Electric's rate Case No. U-21389, the Commission stated on page 148 of its March 1, 2024 order: "The Commission finds the Staff's position and the ALJ's recommendation well-reasoned and supported by the record.

[16] See information on the American Rescue Plan.
[17] See information on the Inflation Reduction Act and the linked White House press release.
[18] Staff's use of "Covid-related" refers to the federal funding increases aimed at lessening the after-effects of the Covid-19 pandemic, such as the American Rescue Plan and Inflation Reduction Act.
[19] See DTE Electric Company's rate book, ninth revised Sheet No. D-2.00 under "Income Assistance Service Provision", which states in part: "For an income assistance customer to qualify for this credit, the Company shall require annual evidence of the HHC energy draft or warrant."

Accordingly, the Commission adopts the ALJ's findings and conclusion on this issue." The referenced ALJ recommendation from her PFD stated:

> This PFD finds Staff's position persuasive. First, Staff's use of an entire year of RIA credits, rather than a simple comparison of customer counts for two months one year apart, more accurately demonstrates the trend in RIA enrollment and the fact that customers do not necessarily reenroll in the program. Second, the company's projection depends on actual enrollment in March of 2023, which appears to be the result of COVID-related LIHEAP disbursements, coupled with speculation about increased numbers due to more outreach and possible future funding from LIHEAP and DHHS. Lastly, the PFD agrees with Staff that without a tracker or deferred accounting, over-projection of RIA credits would result in DTE retaining any overcollection. Thus, an accurate projection for this credit is even more important.[20]

6. Company RSC Projection

Q. Did the Company provide testimony in its initial filing proposing a Residential Senior Citizen Credit (RSC) customer count projection?

A. No.

Q. What revenue recovery figure and number of credit disbursements did the Company include recovery of in its Schedule F-3, rate design model?

A. 104,224 monthly credit disbursements, totaling $5,315,424.

7. Staff RSC Projection

Q. What projection number does Staff support revenue recovery of for the RSC credit?

A. Staff supports using a 3-year historical average of actual RSC credit disbursement amounts, which totals 94,525 with a revenue increase of $494,656 and is

[20] MPSC Case No. U-21398, 12/21/2023, PFD, p. 379.

incorporated on the residential rate schedules in Schedule F-3, sponsored by Staff witness David W. Isakson.[21]

Q. What evidence do you provide to support your position?

A. I cite the historical credit amounts reported in Part III attachment 5(9), which are depicted in the table below.

RSC Credit Disbursements	
Year	**Monthly Disbursements**
DTE-Proposed Test Year	104,224
2022	95,329
2021	94,117
2020	94,129
2019	98,484
2018	109,091

As is evident in the above table, credit disbursement amounts have been relatively stable for the 3 historical years provided by the Company in Attachment 5(9) of its Part III filing requirements. Absent significant interest in or outreach to enroll customers in the credit, there is no evidence on the record that this program would experience a significant increase in enrollment.

[21] Supporting calculations in Exhibit No. S-17.1

Total Population by Selected Age Groups
Michigan 2000-2022

Year	Total	< 18		18 - 44		45 - 64		65 & Over	
		Number	Percent	Number	Percent	Number	Percent	Number	Percent
2022	10,033,757	2,109,759	21.0	3,483,209	34.7	2,560,711	25.5	1,880,078	18.7
2021	10,037,169	2,130,494	21.2	3,467,646	34.5	2,606,972	26.0	1,832,057	18.3
2020	10,069,614	2,154,501	21.4	3,475,155	34.5	2,650,941	26.3	1,789,017	17.8
2019	9,986,857	2,143,933	21.5	3,423,309	34.3	2,654,214	26.6	1,765,401	17.7
2018	9,984,072	2,162,182	21.7	3,415,762	34.2	2,692,772	27.0	1,713,356	17.2
2017	9,973,114	2,180,747	21.9	3,405,184	34.1	2,722,853	27.3	1,664,330	16.7
2016	9,950,571	2,193,921	22.0	3,396,407	34.1	2,742,849	27.6	1,617,394	16.3
2015	9,931,715	2,209,035	22.2	3,398,276	34.2	2,752,697	27.7	1,571,707	15.8
2014	9,929,848	2,230,079	22.5	3,409,065	34.3	2,759,488	27.8	1,531,216	15.4
2013	9,913,065	2,249,312	22.7	3,408,947	34.4	2,767,253	27.9	1,487,553	15.0
2012	9,897,145	2,272,804	23.0	3,405,183	34.4	2,776,100	28.0	1,443,058	14.6
2011	9,883,053	2,301,921	23.3	3,403,024	34.4	2,789,470	28.2	1,388,638	14.1
2010	9,877,510	2,334,175	23.6	3,409,975	34.5	2,767,075	28.0	1,366,285	13.8
2009	9,901,591	2,372,603	24.0	3,449,020	34.8	2,736,345	27.6	1,343,623	13.6
2008	9,946,889	2,418,879	24.3	3,507,576	35.3	2,699,413	27.1	1,321,021	13.3
2007	10,001,284	2,470,063	24.7	3,568,443	35.7	2,671,540	26.7	1,291,238	12.9
2006	10,036,081	2,503,548	24.9	3,634,296	36.2	2,628,794	26.2	1,269,443	12.6
2005	10,051,137	2,531,839	25.2	3,690,254	36.7	2,573,778	25.6	1,255,266	12.5
2004	10,055,315	2,553,314	25.4	3,742,180	37.2	2,512,778	25.0	1,247,043	12.4
2003	10,041,152	2,569,080	25.6	3,785,004	37.7	2,448,494	24.4	1,238,574	12.3
2002	10,015,710	2,584,310	25.8	3,820,033	38.1	2,381,204	23.8	1,230,163	12.3
2001	9,991,120	2,593,310	26.0	3,861,148	38.6	2,310,403	23.1	1,226,259	12.3
2000	9,952,450	2,596,114	26.1	3,889,337	39.1	2,245,700	22.6	1,221,299	12.3

Additionally, as shown in the graphic above[22], the percentage of Michigan residents 65 years of age and older has hardly changed over the past 3 years—especially not enough to warrant the 8.5% increase in the senior credit that the Company is requesting. Therefore, I recommend disapproval of the Company's credit recovery figure in favor of my projection.

8. Summary

Q. Please summarize your positions and recommendations in your direct testimony.

[22] Source: Michigan Department of Health and Human Services online population graphic.

A. Staff proposes the following:

The Commission reject the Company's LIA credit increase proposal to allow this issue to continue to be more fully analyzed and addressed in the Commission's EAAC workgroup;

Updating the LIA tariff language across residential schedules to reflect Company enrollment practices and Commission decisions;

Approving Staff's RIA enrollment projection of 56,134;

Approving Staff's RSC enrollment projection of 94,525.

Q. Does this conclude your testimony?

A. Yes, it does.

S T A T E OF M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*** * * ***

In the matter on 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**

REBUTTAL TESTIMONY OF

ELAINA M. BRAUNSCHWEIG

MICHIGAN PUBLIC SERVICE COMMISSION

August 16, 2024

REBUTTAL TESTIMONY OF ELAINA M. BRAUNSCHWEIG
CASE NUMBER U-21534

Q. Are you the same Elaina M. Braunschweig who filed direct testimony on behalf of the Michigan Public Service Commission Staff (Staff) in the instant case?

A. Yes, I am.

Q. What is the purpose and structure of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to present Staff's response to certain positions taken by Soulardarity and We Want Green, Too, (together the Detroit Area Advocacy Organizations or DAAO) witnesses Jackson Koeppel, Justin Schott, Toyia Watts, Yunus Kinkhabwala, and Arjun Makhijani. Additionally, I'll address positions taken by Environmental Law and Policy Center's (ELPC) witness Willian Kenworthy and Natural Resources Defense Council/Michigan Environmental Council's (NRDC/MEC) witness Roger Colton. Since the testimonies share many similar recommendations, my testimony will be structured based on categories of issues in the following order:

1. Affordability-Based Rates Arguments
2. Percentage of Income Payment Plan Proposals
3. Closing the Energy Burden/Affordability Gap
4. Research and Study Proposals
5. Low Income Assistance Credit and Residential Income Assistance Credit Reform Proposals
6. Summary

1. Affordability-Based Rates Arguments

Q. Please summarize the arguments made in testimonies regarding affordability-based rates.

A. DAAO witnesses Jackson Koeppel and Arjun Makhijani made recommendations on pages 24 and 63 of DAAO witness Koeppel's testimony and page 56 of DAAO witness Makhijani's direct testimony to seek Commission approval for a universal affordability program that would be available to all residential customers. DAAO witness Justin Schott also recommended a unified affordability program on page 58 of direct testimony and, on page 69, capping all customers' rates at 6% of their income.

Q. What is your position on these proposals?

A. My position is that these proposals not be approved by the Commission due to prevailing statutes.

Q. What statutes do you cite?

A. I cite MCL 460.11, subsections 1 and 2 and MCL 460.10(t) to raise the issue of eligibility for low-income rates and revenue allocation. Legal application of statutes will, however, occur in brief. Additionally, I raise the issue of verifying all incomes with universal enrollment.[1] Hurdles to implementing a percent-of-income rate proposal for all residential customers include building necessary trust with customers to collect sensitive data (like income), the difficulty to get all customers to respond to an income query and the likelihood of high staffing costs to update income annually. Staff supports customers reaching out and receiving

[1] "Universal enrollment" is enrolling all residential customers regardless of their income level.

assistance if eligible but does not currently support requiring income reporting of all customers.

2. Percentage of Income Payment Plan (PIPP) Proposals

Q. Please summarize the proposals relating to PIPPs in direct testimonies of intervening parties' witnesses.

A. A brief summary is as follows: DAAO witness Justin Schott proposed on page 68 of direct testimony to accelerate the development of PIPPs. DAAO witness Toyia Watts proposed on page 15 of direct testimony to approve a unified form of assistance or a PIPP. On pages 18 through 19 of direct testimony, DAAO witness Yunus Kinkhabwala proposed a PIPP as the most comprehensive bill-assistance approach to reducing energy burdens and that it should be implemented for customers whose income is at or below 200% of the federal poverty level (FPL).

Q. Do you support these proposals?

A. No; as described in my direct testimony, evaluating the cost and effectiveness of Consumers Energy's and DTE Energy's PIPP pilots is what the EAAC's Affordability, Alignment, and Assistance subcommittee and Staff are currently working on. Staff does not support the premature approval of a full-scale PIPP and recommends the Commission allow this analysis and energy assistance restructuring recommendations to come from the AAA and Staff and hold off on utility energy assistance programmatic changes until that point.

Additionally, it is relevant to reference the statute MCL 460.11(2) and its corresponding list of eligibility criteria under MCL 460.10(t) as in the previous section. Legal interpretation of statutes, will, however, occur in Staff's brief.

3. Closing the Energy Burden/Affordability Gap

Q. What proposals were made to financially quantify and close the gap between the current energy assistance available (in dollars) and what is considered "affordable?"

A. On page 24 of direct testimony, DAAO witness Koeppel proposed the Commission approving a charge of 0.743 cents per kWh for all customers, which is what DAAO witness Makhijani estimated as the cost to close the energy affordability gap for all residential customers based on DTE's projections.[2] Additionally, DAAO witness Kinkhabwala also proposed approving a charge of 0.18 cents per kWh to just fund an additional $10 million in energy assistance on page 30 of direct testimony. On pages 8 and 9 of DAAO witness Kinkhabwala's testimony, they calculate $90 million of "available" funding for their proposed PIPP by including federal Low-Income Home Energy Assistance Program (LIHEAP) and Michigan Energy Assistance Program (MEAP) dollars. I could not find a calculation for how witness Kinkhabwala calculated that number.

Q. What is your reaction to these proposals?

A. It is unclear how these funding factors would be levied on all customers if DAAO also proposes limiting all residential customer bills to 6% of income. Approving these proposals could lead to significant revenue shortfalls or increases in the residential class and could complicate the Commission's compliance with MCL 460.11(1) and MCL 460.11(2), since it seems DAAO witness Koeppel's 0.743 cent per kWh surcharge would fund a universal affordability program for all

[2] Direct testimony of DAAO witness Arjun Makhijani, page 28

customers that express a difficulty paying their bills.[3] Furthermore, there is an additional issue with generating the revenue through a surcharge to fund the proposal. Customers with capped bills may not generate any revenue via the surcharge due to their bill being capped, which would lead to a revenue shortfall for both funding the initiative *and* for base rates. If the revenue from a customer's bill is applied to the surcharge first, then the capped-bill customer would contribute even less to base rates, thus exacerbating the revenue shortfall from the residential class.

I therefore do not support these proposals and instead reiterate the Commission should allow analysis of energy assistance restructuring and associated recommendations to come from the AAA and Staff reports and hold off on utility energy assistance programmatic changes until that point. DAAO's witnesses' proposals would complicate the energy assistance landscape even more, which conflicts with DAAO witness Watts' testimony to make energy assistance more unified.[4] Staff supports streamlining assistance, but recommends it be accomplished in the Commission's EAAC in a coordinated and collaborative fashion across all investor-owned utilities, as the workgroup has already dedicated time and education to how energy assistance can be better utilized and streamlined.

4. Research and Study Proposals

[3] Direct testimony of DAAO witness Koeppel, page 25
[4] Direct testimony of DAAO witness Watts, page 15

Q. What research and studies did intervening parties' witnesses propose in direct testimonies?

A. On page 77 of direct testimony, DAAO witness Schott recommended the Commission's low-income workgroups research and submit affordability structures to the Commission 90 to 120 days after the final order in the instant case.

Q. What is your reaction to these recommendations?

A. DAAO witness Schott's recommendation is, if I interpret "affordability structures" correctly, already underway in the development of utility PIPP reports and in the AAA subcommittee as the group and Staff work to ensure bill impact is considered in the analysis of utility energy assistance. The Commission should therefore not approve this duplicative work, the proposed deadline for which should coincide with Staff's timeline for PIPP reporting and analysis, mentioned in my direct testimony.

5. Low Income Assistance Credit (LIA) and Residential Income Assistance Credit (RIA) Reform Proposals

Q. Please summarize the testimony making recommendations to restructure the RIA and LIA credits.

A. NRDC/MEC witness Roger Colton provided testimony recommending the RIA remain at $8.50 per month but redirecting RIA credits to those with special needs[5] up to 250% of the federal poverty level (FPL) or 60% of state median income

[5] He seems to define "special needs" as those who are on protection plans on page 27 of his testimony.

(SMI),[6] making public assistance a qualifier for RIA,[7] transfer RIA customers to become LIA customers,[8] put those new LIA customers on a tiered LIA credit structure,[9] and reconcile costs on an annual basis.[10] Additionally, he recommends removing the capped enrollment on RIA and LIA[11] and expanding LIA enrollment to include self-attestation of other benefits.[12]

Q. Do you agree with witness Colton's proposals mentioned above?

A. No, I do not. As I already mentioned in direct testimony and in this rebuttal testimony, Staff recommends the Commission allow energy assistance restructuring analysis and recommendations to come from the AAA and Staff reporting on LIA, RIA, and PIPP pilots and hold off on utility energy assistance programmatic changes until that point.

Staff's rebuttal of NRDC/MEC witness Colton and many other intervenors' recommendations reinforce the importance of allowing this work to occur through the chronological format of a utility report, Staff-response, a comment-period, and Commission order. Staff's issues with many of witness Colton's recommendations show how the complicated landscape of energy assistance can lead to misunderstandings and recommendations that have significant hurdles to implement—or recommendations that are already occurring or have been identified as problem-areas by the EAAC. Ultimately, however, the Commission

[6] Direct Testimony of NRDC/MEC witness Roger Colton, p. 4
[7] *Id.*
[8] Direct Testimony of NRDC/MEC witness Roger Colton, p. 5
[9] *Id*.
[10] *Id*.
[11] *Id*.
[12] *Id*.

does not have jurisdiction over many areas of the energy assistance landscape, as I will discuss in order of the listed recommendations, above.

Responding to NRDC/MEC witness Colton's first proposal Staff identified, the RIA and LIA are the Commission's initial fulfillment of and authorized under MCL 460.11(2), with eligibility defined in MCL 460.10(t), and Staff recommends utility-based low-income programs adhere to those statutes. For clarification, the RIA is currently held equal to the residential customer charge, so it could change amounts consistent with the Commission's final order on the customer charge in the instant case. It is unclear from NRDC/MEC witness Colton's testimony if the RIA and LIA would have overlapping customers from 0-150% of the FPL under his proposal or explicitly how the RIA and LIA would have distinct customer pools. In response to the identified second proposal, many forms of public assistance are qualifiers for the RIA,[13] however, only LIHEAP programs[14] and MEAP programs can realistically automatically enroll a customer in the RIA because of privacy restrictions within the Michigan Department of Health and Human Services (MDHHS). So, even though SNAP and Medicaid are eligibility criteria under statute, MDHHS does not currently allow the release of those recipients' information or corresponding utility accounts to be shared with utilities. This is something that the AAA discussed and tried to (unsuccessfully) negotiate with MDHHS representatives. Third, Staff does not support programmatic changes being made to the RIA and LIA at this time, since these

[13] SNAP, Medicaid, MEAP and LIHEAP programs
[14] State Emergency Relief, Home Heating Credit, and programs such as Energy Direct that MDHHS may allocate additional dollars to.

programs are under review. This includes but is not limited to changing the structure of how the credit is used, increasing the credit amount of and increasing enrollment of the LIA credit. Staff responds to NRDC/MEC witness Colton's statements, however, by noting that the RIA is already an uncapped program, meaning all that qualify and/or apply can receive the credit. Its enrollment is simply projected in each rate case and costs are recovered by ratepayers. Fourth, I find it imprudent to not have a cost estimate or study done to know how much NRDC/MEC witness Colton's tiered LIA would cost, even if its cost differences would be reconciled, according to pages 37 and 38 of witness Colton's direct testimony. This is one reason why Staff supported a percentage of income payment plan pilot, since pilots allow interested parties to understand the costs and outcomes of energy assistance programs.

Finally, to my understanding, DTE offers self-attestation to RIA customers even though it is not explicit in the tariff, so I therefore propose to add language to the RIA and LIA tariff language to explicitly say that:

"If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return." This is standard language that has been approved by the Commission for other utilities. Most notably in MPSC Case No. U-20917 for DTE Gas Company, in which language similar to the above language was added to the Income Assistance Service Provision (RIA).[15] Since Staff believes this practice is already occurring, the language should be added to both the RIA and LIA

[15] See MPSC Case No. U-20917 1/21/2021, Order and 12/2/2020 revised Attachment 1.

(currently rate schedule D1.6) regardless of the Commission's decision on discontinuing schedule D1.6.

6. Summary

Q. Please summarize your rebuttal testimony.

A. I recommend the Commission reject the following proposals from intervening parties:

Offering universal residential percentage of income capped rates;

Implementing percentage of income payment plans for income-qualified customers before the Commission reviews the outcomes of the Company's pilot;

Implementing surcharges to close the energy affordability gap;

Having the EAAC provide duplicative analyses on affordability structures; and

Reworking the entire structure of the RIA and LIA and expanding the LIA program.

However, Staff does support making the self-attestation option for the RIA and LIA explicit in the Company's tariff and the Commission should approve adding that language to the tariff language that Staff is already proposing.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

JUDGE WALLACE: Mr. Bzdok, please go ahead.

MR. BZDOK: Thank you, your Honor.

CROSS-EXAMINATION

BY MR. BZDOK:

Q Good morning, Ms., is it Braunschweig?

A Braunschweig.

Q Braunschweig. Good morning.

A Good morning.

Q My name is Christopher Bzdok, we've never met before, but I represent MEC, NRDC, Sierra Club, and CUB in this case, and we filed testimony, among other witnesses, by Roger Colton. Do you know who that is?

A Yes.

Q O.K. Just one second. I want to look a little bit at your direct testimony today, and then also at your rebuttal testimony today, and the specific subject of my focus is your position that certain proposals made in this case should not move forward because of, they were not made through certain workgroups or collaboratives that the Commission has ongoing, and we can talk about that a little bit more as a policy matter.

As I understand it, you co-lead something called the Affordability, Alignment, and Assistance Subcommittee in the Commission's Energy, Affordability,

and Accessibility Collaborative; is that right?
A That's correct.
Q And the Affordability, Alignment, and Assistance Subcommittee is referred to in testimony in this case as the AAA, or the Triple A, or is there a short version of that?
A The AAA subcommittee is fine.
Q O.K. And the Energy, Affordability, and Accessibility Collaborative is referred to as the EAAC; is that right?
A That's correct.
Q Do you have a short, you call it an E-AAC or anything like that?
A The EAAC I think is the shortest thing we call it by.
Q O.K. Sorry I talked over you, I didn't mean to. Let's take a look at your direct testimony, and I'm looking at page 5 as a start.
A O.K., I'm there.
Q At the bottom of page 5, you testify that the Commission should reject DTE's proposal to increase the Low Income Assistance/LIA credit from $40 to $50 per month; is that correct?
A That's correct.
Q And what is the LIA credit, just for context?
A Can you clarify what you would like to know about it?
Q At high level or generally, what is it, what does it do?

A It's a $40 per month credit for qualifying customers per month.
Q And again -- go ahead.
A Yeah, just $40 per month credit.
Q O.K. And high level, can you characterize the qualifying customers for me, what characteristics qualify them?
A I cite a statute in here that outlines the qualifications, but the tariff outlines the qualifications as well. The statute is MCL 460.10t that outlines the qualifications for a customer under statute MCL 460.11(2).
Q Eye level, in your own words, what characteristics, what customer characteristics is the LIA credit aimed for, what population?
A A low-income population. Generally 150% of the federal poverty level and below.
Q O.K. Referring to -- so who sponsored that proposal for DTE?
A Witness Jason Sparks.
Q O.K. And in your testimony referring to Mr. Sparks, elaborating on the recommendation to reject increasing the LIA credit from $40 to $50, you state on page 6 at the top, quote: He, meaning Mr. Sparks, does not provide the comprehensive analysis and diverse, collaborative input the Commission is looking for to inform utility

energy assistance changes. Do you see that?
A I do.
Q And then you say: As indicated by the cited orders, which you mentioned earlier in your testimony, this collaborative RIA/LIA reform work is being performed in the EAAC workgroups, right?
A Correct.
Q And then you state: Staff's position is that collaborative discussions with interested/invested parties as well as all investor-owned utilities will lead to the most informed position and decisions on this matter. Right?
A Correct.
Q Do you have access to the SharePoint file for this case?
A I do.
Q O.K. And so specifically within the Michigan Public Service Commission Staff folder, there's a folder with your name on it; is that right?
A Correct.
Q And then there's one within that folder that says MNSC Exhibits for Braunschweig. Do you see that?
A Yes, I do.
Q So take a look at that and open it up and you'll see that a few seconds ago I uploaded a document that is DTE's application in this case. Do you see that?

A Yes.
Q O.K. Could you open that one up.
A Yes.
Q So if you open that one up --
A Yes.
Q Go ahead.
A Sorry, I just said that yes, I opened it.
Q O.K. It takes a while to get used to this format, I've been doing it for I won't even tell you how many years and it still, I still stumble.

O.K. So in that, in that application document, there is a, I guess it would be page 12 of that PDF there's an Attachment 4, which is a proposed notice of hearing. Can you turn to that.

A What page did you say it was?
Q It's page 12 of the PDF, which is Attachment 4 to the application.
A Oh, yes, I'm there.
Q O.K. So in the first bullet point of that proposed notice of hearing, there's an outline of DTE's proposed increase in its annual base electric revenues of $456.4 (with additional revenue requirements, et cetera et cetera, for the Investment Recovery Mechanism or IRM), do you see that?
A Yes.

Q And then in all capital letters, and I believe this is an MPSC requirement, there's a statement, "A typical residential customer's average electric bill may be increased by up to $11.03 per month, if the Michigan Public Service Commission approves the request," right?
A Correct.
Q So if the -- and I understand that rate increases are typically not granted in full, but if this rate increase was granted in full and the -- sorry, I have something coming on my Teams phone I've got to stop. So if the rate increase was granted in full and the DTE's LIA proposal was granted in full, and we assume that an LIA customer uses average rates, they would still fall -- they'd still slip about a dollar a month when all was said and done; would you agree hypothetically that that seems plausible?
A It depends on who the LIA customer is.
Q Yep. Typical, average, high-level assumptions, would you agree?
A Not necessarily, because some of the LIA recipients are enrolled in an affordable payment plan, so if it's the customers who are not in the affordable payment plan, then yes, I can agree, the ones who are in the affordable payment plan, then likely not.
Q O.K. And all of that sort of discussion relates only to

base rates; would you agree? Well, let me rephrase that question, that was awkwardly phrased.

So assuming that there is a level of rates set in a, base rates set in a rate case, additionally from year to year there can also be increases in customer bills as a result of increasing PSCR surcharges from year to year; would you agree on principle with that?

A Yes.

Q So if there are increases, ongoing increases annually in DTE's PSCR surcharges, a customer on LIA without the affordability payment plan would also slip a little further behind as a result of those PSCR surcharge increases even if DTE's LIA $10 increase proposal was approved, right?

A Likely, yes.

Q Do we need more analysis to know that these folks would fall further behind or is that a fairly straight-forward conclusion to draw?

A Yes, I think so.

Q By yes, you think so, you're agreeing with me that that's a fairly straight-forward conclusion to draw and we don't need further analysis?

A On that, specifically of them falling behind or them experiencing rate increases, then I agree with you.

Q O.K. Are you aware that my witness, Roger Colton, five years ago in 2019 in Case No. U-20561 proposed increasing the LIA credit for DTE Electric's customers, low-income customers, from $40 to $60?
A I don't remember that specifically, but it sounds familiar.
Q O.K. In that five-year time period, the LIA credit has remained the same, correct?
A Correct.
Q Do you know how many times DTE Electric's base rates have increased in that time?
A Potentially three or four.
Q I agree with you, it's somewhere in there. Do you know how many times their PSCR surcharges have increased in that time?
A I can not be certain of that.
Q O.K. You also filed rebuttal testimony in this case; is that right?
A That's correct.
Q And in your rebuttal testimony, you recommended against proposals related to low-income tariffs and programs by parties, including the Detroit Area Advocacy Organizations, the Environmental Law & Policy Center and it's aligned groups, and NRDC/MEC Witness Roger Colton; is that right?

A Broadly speaking, yes.
Q O.K. And you give some specific concerns as to some specific proposals, and you also give some general testimony about process; is that fair?
A Broadly speaking, yes.
Q So for example, on page 5 in response to the Detroit Area Advocacy Organizations, or DAAO groups, you state starting at line 9 I think, "I therefore do not support these proposals and instead reiterate the Commission should allow analysis of energy assistance restructuring and associated recommendations that come from the AAA and Staff reports and hold off on utility energy assistance programmatic changes until that point," correct?
A Consistent with past Commission orders, correct.
Q And on page 7 of your rebuttal testimony in response to Mr. Colton, his proposals for this case, you state starting at line 7, "As I already mentioned in direct testimony and in this rebuttal testimony, Staff recommends the Commission allow energy assistance restructuring analysis and recommendations to come from the AAA and Staff reporting on LIA, RIA, and PIPP pilots and hold off on utility energy assistance programmatic changes until that point," correct?
A Correct.
Q O.K. When did the collaborative begin, the EAAC?

A I can't remember if the collaborative began before the subcommittee started convening, but I can say that the AAA subcommittee started convening in either July or August of 2021.

Q O.K. And did it commence in response to a Commission order in Case U-20697?

A No. I believe it was 20757, but I could be wrong.

Q O.K. Bear with me a second. So take a look in the SharePoint folder, there's Exhibit proposed MEC-127. Let me know when you're there.

A I just opened it.

Q This consists of Discovery Responses from you labeled 1c and 1d; is that right?

A Correct.

Q And in Response 1c, we asked you for any government -- excuse me -- governance-related documents for the AAA, correct?

A Correct.

Q And you indicated there were no governance-related documents per se, but you provided some other documents that had to do generally with the topic of the EAAC's charge, the AAA's charge, and various Commission directives over the years, correct?

A Correct.

Q O.K. And one of the documents that you identified as

relevant to these topics was a summary of Commission orders; is that right?

A Correct.

Q And if you look at proposed Exhibit MEC-129 --

A I just opened it.

Q O.K. That is the summary, subject to my representation I've not modified any of these documents, that is the summary of Commission orders that you're referring to in the prior response; is that right?

A That is correct. However, I think there needs to be a little bit of clarification that this -- the EAAC subcommittees have received two rounds of directives from the Commission in the 20757 docket, and these, this document was for the second round of directives.

Q O.K.

A That summarizes Commission orders that referenced the EAAC which shaped the second round of directives that the Commission would have approved in its December order in the 20757 docket, December 2023 order, for clarification.

Q O.K. So I'm looking at the, U, the order that's under the heading U-20697 on the first page of that summary that we do have.

A Yes, I see it.

Q And there is a quote in the middle, it's -- well, the whole thing is a quote from the order, right, pages 12

and 13?
A Yes, I think so.
Q And in the block quote within the quote, the Commission is quoting its own order from the 20757 docket; is that right?
A Yes, I think so.
Q O.K. And that order in the 20757 docket includes a directive to Staff to convene a low-income collaborative with the participation of Consumers to address energy affordability, it's kind of right in the middle of that block quote; do you see that?
A Yes, that would have convened the start of the EAAC.
Q O.K. So that would be the origin of the EAAC would be the order in 20757 in December of 2020?
A I think the workgroup, it looks like it was convened potentially July 23, 2020, at the end of that block quote, and this might have been a quote from -- about a report that Staff filed in December of 2020 in the 20757 docket, I think that's what this is clarifying, but I would need time to read this a little more thoroughly to fully vet it.
Q O.K. Now, do you recall from your review of these orders there were certain proposals made by Roger Colton in 20697 for the Attorney General and what we now call MNSC, what we used to call the MEC coalition; do you recall

that?
A Where do you see that on this document?
Q So I'm looking at the paragraph below the block paragraph where it says: The Commission finds it addressed all of the proposals and objections presented by the AG/MEC Group in the underlying proceeding.
A Yes, I see that.
Q So do you recall that Mr. Colton also made proposals relative to low-income rates and tariffs in 20697?
A It's been a while since I've reviewed that case, so I don't remember that.
Q I certainly agree it's been a while. O.K. And do you recall whether those proposals were redirected to the collaborative or workgroup in 20697?
A I don't recall that.
Q O.K. Who are the members of the EAAC?
A Can you clarify if you would like organizations or names or what you're looking for?
Q Sure. Let's do organizations.
A I can't speak for the EAAC as a whole because I lead a smaller part of it, so I don't see the full distribution list, but I can speak for the AAA subcommittee and say that it is MPSC Staff members, utility, representatives from utilities, namely the investor-owned utilities that the MPSC regulates, there are also representatives from

Michigan Energy Assistance Program grantees, and that involves a wide variety of organizations, there are some impacted customers in that group, as well as other interested parties that aren't dissimilar to the parties who intervene in this case or other similarly contested proceedings. That's what I can think of off the top of my head, but that doesn't mean that it's excluded to that.

Q O.K. How is membership formalized, if at all?

A Can you define formalized?

Q What determines whether you're a member of the AAA?

A If you seek to be a member of the AAA, then you are forwarded all of the meeting invites, you're included on the circulation list, it's as people are interested; I'm not involved in any sort of recruitment, though.

Q O.K. When did the AAA begin?

A I think July or August of 2021.

Q O.K. How does the AAA make decisions if the members do not have unanimity on a topic?

A It report, the -- the workgroup functions based off of reports in terms of making decisions or recommendations. I guess we don't make recommendations -- we don't make decisions as the group, the Commission makes final decisions. So Staff writes a report summarizing what has occurred, the work that has taken place, any sort of

dissent that has happened in the group, so that would be what you're getting at of, you know, if there is a disagreement, then we note that disagreement and try to incorporate it in options for our recommendation; otherwise, in the most recent report, the Commission opened a comment and reply comment period after the report for interested parties or people to file comments about.

Q O.K. I want to pick up on that thread, but just for the record, when you say in the most recent order, are you referring to the December 21, 2023, order in 20757?

A Yes.

Q O.K. So Staff writes the report; is that right?

A Yes, and we've sent it out to the subcommittee for review historically before filing it.

Q O.K. And if there is not consensus or unanimity on recommendations in the report, that's noted in some way?

A Yes, the AAA subcommittee has noted dissent in its reports.

Q The recommendations themselves, that, the determination of what will be recommended is a determination made by Staff, then?

A Based on what has occurred in the subcommittee, yes.

Q O.K. I think you indicate in the your rebuttal testimony that the AAA is preparing a report on -- I always just

call it the PIPP, and I have to think for a minute about what the acronym is. What is the PIPP, the P-I-P-P?

A The Percentage of Income Payment Plan pilot.

Q So it's the P-I triple P?

A Essentially, yes.

Q So the AAA is preparing a report on the PIPP that will be issued in 2025; is that right?

A Yes.

Q What's the scope of that report?

A Well, first of all, the report will be a response to the utilities' filed reports on their PIPPs. So they first have to file their reports, which should include other aspects of energy assistance besides just the PIPP, so other programs like the RIA and LIA for the affordable payment plans, that should be included in their recommendations and decisions in their report, and then Staff or the AAA's report that responds to that will react to whatever the outcomes of that report are, as well as incorporating the analysis that has occurred in the AAA subcommittee regarding the RIA and LIA credits. So kind of a holistic or over-arcing view and recommendations for energy assistance programs.

Q Can you repeat what you said about the RIA and LIA credits piece of that answer? I was getting down the other part of your answer, but then I missed that part.

Can you repeat what you said about that?
A That I think that the, both the utilities and Staff will be, should include some analysis or include recommendations about the LIA and RIA, consistent with the Commission's December 2023 20757 report, I think that's essentially what I said, and that the Staff will include its analysis from the AAA subcommittee about those credits.
Q O.K. Bear with me a second. So you mentioned, I think in that answer you might have called it a report when I asked you to repeat it, but you were referring to the Commission's December 2023 order in 20757, right?
A Yes. Sorry.
Q No, no problem at all. That, so that order, the only thing that that order discusses in terms of the LIA credit is it adopts a recommendation relative to utility reporting on the LIA credit; is that right?
A I would need to see the recommendation before confirming that.
Q O.K. So that order is in the SharePoint in your folder.
A O.K.
Q I don't know how actively -- I don't know if whether you can see my active work in a SharePoint document or not.
A What page are you on in that order? I have it opened.
Q O.K. So I'm in recommendation 1.5 starting at page 13.

A O.K., I'm there.
Q O.K. So the only substance, the only discussion of any recommendation I can find in this order related to LIA is this discussion of a recommendation relative to utility reporting on the LIA. Do you have any reason to disagree with that?
A I disagree with the framing of that because it's not LIA reporting, it was an order in a previous DTE Electric case that ordered the EAAC to analyze an LIA report filed by DTE Electric Company about the use of the credit and enrollment cap, I believe.
Q O.K. So that is with reference to some other order?
A Yes, the 20836 order.
Q O.K. When -- bear with me a second. O.K. So Staff will issue a report that will be a review of the utility reports on their PIPPs, and will also address in some way RIA and LIA credits; is that right?
A Yes. I cite the 20757 December 21, 2023, order on page 5 of my direct testimony, which -- I want to find that direct quote from there because that's the best response to what Staff is charged with in that report --
Q O.K.
A -- so give me one moment.
Q O.K.
A Yes. At pages 14 and 15 of that December 21, 2023,

order, say: The Commission looks forward to the AAA subcommittee evaluation of the RIA and LIA as a fulfillment of MCL 460.11(2), and directs the utilities to work with the Staff to provide necessary data to that end. In addition, the Commission directs the Staff to combine this analysis with comparative analysis of PIPP pilots and the MEAP offerings, that's Michigan Energy Assistance Program offerings for clarification --

Q Yep.

A -- to ensure a comprehensive understanding of current offerings. So that's what Staff's report should be on is a combined analysis of the PIPP/MEAP programs and fulfillment of MCL 460.11(2), which the RIA and LIA are the current fulfillment of that legislation. So that will be a combined analysis of all of those programs.

Q And that report is expected when?

A In 2025.

Q Do you know when?

A It's going to depend on when the utilities file their reports. It should be either the first or second quarter of 2025.

Q O.K. And then will there be another comment and reply period on the Staff report?

A That is up to the Commission to determine.

Q So that's unknown at this time?

A Correct.
Q O.K. If, so either after Staff files its report and there's no further activity, or if after Staff files its report and then there's a comment and reply period and a Commission order, at some point the process around the PIPP, RIA, and LIA analyses will complete; is that right?
A The AAA will complete its analyses, unless otherwise ordered by the Commission.
Q O.K. Thank you for that. That's a good clarification. And at that point, are the utilities required to file proposals that align with the AAA's recommendations on those topics?
A Can you repeat that question?
Q At that point, when the AAA completes its work on RIA, LIA, and PIPP, are the utilities required to file proposals that align with those recommendations?
A Currently, the -- in the current -- currently Staff would like for the utilities to make recommendations based on the PIPP pilot outcomes. I do not know if the Commission will require the utilities to make additional proposals after Staff files a report.
Q The -- let me try it a different way. So the, this report and recommendations process is not self-executing, right, it does not lead directly to new or revised programs, rates, or tariffs; would you agree?

A I disagree because that's up to the Commission to decide in its order.
Q Let me try it a different way. So I think you said a few minutes ago we don't know if there would be another reply comment in the Commission order period, right?
A I don't know if there would be a reply comments after Staff files its report since that's up to the Commission.
Q O.K.
A I would suspect the Commission would come out with an order after Staff's report, as is generally standard in the 20757 docket.
Q O.K. That report -- sorry. That order following Staff's report, based on the history of the 20757 docket, that report can't directly insert programs, rates, or tariffs in the utility's Rate Book, right, there still need be rate cases, don't there?
A Tariffs can be revised through ex parte cases; cost recovery has to occur in a rate case.
Q O.K.
A So I would once again say that it is up to the Commission order how that is handled.
Q There would need to be subsequent proceedings, they might be rate cases or they might be ex parte?
A Likely. I can't be certain of that.
Q O.K. And the utilities may follow the AAA's

recommendations in their proposals exactly or they may not, right?

A Follow them in what way?

Q Align, they may, their proposals may be aligned with the outcome of the AAA process or they may do something different, right?

A Correct. They're not -- the utilities don't have to recommend specifically what occurs in the AAA.

Q And those decisions, then, will still need to be made either in rate cases or ex parte dockets sometime down the road from the conclusion of the AAA process; would you agree?

A Likely, yes.

Q Do you have any more sense -- do you have any sense of how many times DTE Electric's base rates my increase before the conclusion of that process?

A No, I can not be certain.

Q Could be up to two or three --

A I don't --

Q -- is that fair?

A I wouldn't quantify it, I couldn't say.

Q O.K. Are you aware -- O.K. Take a look at that SharePoint folder again. In that SharePoint folder in the that 1c document --

A What is a c document?

Q Sorry. Sorry. I've been doing this too many days in a row and my talking is getting, slipping a little bit. Bear with me a second. The proposed Exhibit MEC-127 where those two Discovery Responses from you, 1c and 1d?
A Yes.
Q So take a look at --
A I'm there.
Q O.K. So take a look at Response 1c again.
A O.K. Yes.
Q One of the other documents that you identify as being relevant to governance for the AAA is slides 5 to 11 of an April 18, 2023, presentation; is that right?
A Yes.
Q O.K. So in your, that folder, there's a proposed Exhibit MEC-128. Would you open that, please.
A Yes, I have opened it.
Q O.K. This is the presentation that is referenced in that response?
A Yes, I think so. I can't confirm since this one, we weren't dating them at the time, so I can't confirm that this was specifically that month, but we can utilize this document.
Q O.K. Bear with me a second. I don't know how tightly to close the loop on that. Does this look familiar to you as the one you were referring to in preparing that

response?
A Yes, it looks familiar.
Q O.K. So looking at the slides you identified, slide 5 identifies the charge of the AAA subcommittee, right?
A Yes.
Q And then slide 6 is a guiding statement that the membership I presume had agreed on at some point?
A Yes.
Q Guiding principles, same thing?
A Correct.
Q There's a recap of work on slide 8?
A Yes.
Q Correct. O.K. And then there's a recap starting on slide 10 of a report issued in 2022; is that right?
A Yes.
Q There's a proposed AAA charge on page 58 awaiting Commission approval, correct?
A Yes.
Q And that includes a stakeholder discussion on DTE's LIA credit program; is that right?
COURT REPORTER: I'm sorry, did you answer?
A Yes, I said yes.
Q (By Mr. Bzdok): O.K. And that's, that -- the submittal of the report and recommendations that the Commission

referred to there, is that the, is that the process you were talking about a little bit earlier this morning where that will be part of the Staff report in 2025 that includes PIPP but also includes some LIA and RIA discussion?

A Yes, the Staff part of that report, yes.

Q O.K. And then there's another bullet on LIA and RIA, right?

A Yes.

Q And then there's a bullet to: Evaluate the feasibility of a low-income customer subclass in the Cost-of-Service-Study (COSS), correct?

A Yes, that was assigned to the EAAC from a Consumers electric case.

Q O.K. The order, this December 2023 order in 20757 that we talked about, that you talk about in your testimony and we talked about a few minutes ago, that includes a recommendation that the, the Michigan Energy Efficiency for All group had made relative to the charge of, the charge of the AAA, right, there were some changes proposed to the charge or scope of the AAA?

A Yes. That was part of the comments that were filed in response to the report. I can't recall the absolute specifics on those comments, but it does sound familiar, what you're saying.

Q O.K. Bear with me a second. So there's a, there's a discussion in recommendation 1.1 in that order, starting on page 7 where the Staff had recommended the Commission provide an updated charge for the AAA subcommittee to reflect potentially unaccomplished work from the original charge, newly identified topics, and/or work that's been proposed to be addressed by the AAA subcommittee in an updated EAAC structure; do you see that?

A Yes, I do.

Q And MEEFA suggested that the charge should be, one of the amendments to the charge should be to include rate design and cost allocation within the charge of the group at least as it relates to low-income issues, correct?

A Yes.

Q And the Staff opposed including rate design and cost allocation in the MEEFA's -- sorry -- in the AAA subcommittee's revised charge; is that right?

A Correct.

Q And the Commission decided not -- and the Commission basically adopted the Staff's recommendation and chose not to include cost allocation in the AAA's revised charge, correct?

A I believe so. I think you're a little bit ahead of me in the document, but from what I remember, yes. Oh, and I see the area on page 9 where the Commission supports

that, Staff's recommendations, yes.
Q And then declines to revise it on page 10?
A Yes, I see that.
Q And indicates that cost of service and similar issues are heavily contested and are most appropriately considered in the context of contested proceedings, such as a general rate case, right?
A Correct.
Q So I'm trying to square the committee's activity around evaluating the feasibility of a low-income subclass in the Cost-of-Service Study with the committee's not having a charge to consider cost allocation because the Staff opposed it and the Commission rejected it. Do you have any comments on that?
A The cost allocation that I believe Staff was opposed to is discussing and debating how costs are allocated, but that is not best suited for the AAA subcommittee, whereas the part of the charge where the AAA reviewed the low-income subclass in the Cost-of-Service Study for Consumers Energy was determining the feasibility of that subclass based on -- sorry, give me one moment while I collect my thoughts.
Q Take your time, and we're almost done.
A It was more so based on like current cost allocation, current, like currently approved cost allocation, so it

wasn't debating the cost allocation, that Consumers Energy low-income subclass, it was more so reviewing what it would be under the current, currently approved allocations. So yeah, I think that succinctly summarizes the difference.

Q O.K. In proposed Exhibit MEC-127, which was those two discovery responses, we asked you in Question 1d to identify any and all proposals, reforms, or changes discussed at AAA meetings that have subsequently become included in DTE Electric tariffs or rates, and if so, some more specifics around that, right?

A Correct.

Q And you indicated that Staff is unaware of any AAA reform proposals or AAA recommendations to the Commission that have led to tariff or rate revisions to date, fair?

A With the added context in there that it's possible that the work that AAA has done and the discussions that have taken place have influenced subsequent testimonies or the parties involved, yes, that was the response.

Q O.K. Thank you.

MR. BZDOK: Your Honor, at this time I would move to admit proposed Exhibits MEC-127, which were the two discovery responses for Ms. Braunschweig; MEC-128, which was the meeting presentation from April 18, 2023, which we discussed; and MEC-129, which

was the summary of Commission orders related to the EAAC, which we also discussed.

MS. DURIAN: Staff objects to admitting those exhibits without admitting the rest of the First Discovery Response on the basis that some of the questions interrelate to other questions or reference them, and that it would be more complete to admit the entire discovery response.

JUDGE WALLACE: Mr. Bzdok.

MR. BZDOK: So the entire discovery response was a large file of basically every document that the EAAC has addressed in its EAAC and/or AAA has addressed in its four or five years of existence, and I didn't think those other documents were germane to this exam, and so I have not asked about them. The rule of completeness is a rule that a complete document needs to be submitted, it is not a rule that a complete, that every document in a document production needs to be submitted, there's no rule like that. And so if Staff wants to enter documents into evidence, that's their prerogative, but I have moved for the admission of complete documents, and so the rule of completeness would not apply and would not be a basis for objecting to my motion.

MS. DURIAN: I'm not sure if I was clear,

but I meant to point out that 1c is specifically one of the documents that MEC has chosen, and 1c directly references 1a, so I believe 1c would not be complete without 1a.

MR. BZDOK: So is your objection only to 127, then, Heather, and you just want 1a through d, or did you want all the documents in the production?

MS. DURIAN: Yes, I believe that would be sufficient to -- and that I could narrow this objection to MEC-127 to include 1a, the links in 1a.

MR. BZDOK: That's fine with me. I'm happy to take that as a -- we can do an amended exhibit for 127, and we can include -- bear with me a second -- and I guess we might as well include 1b while we're at it, which really is just a, I mean if you want, it doesn't matter to me. I'm happy to add 1a to Exhibit MEC-127, though.

MS. DURIAN: 1a through c would, Staff would agree to having 1a through c.

MR. BZDOK: 1a through d?

MS. DURIAN: Sure.

MR. BZDOK: So we'll do a complete 1a through d for MEC-127, and we will get that uploaded and everything. And so I would amend my motion to admit MEC-127 with the amendment just described to include 1a

through d, and MEC-128 and 129 as presented.

MS. DURIAN: Staff withdraws its objection.

JUDGE WALLACE: All right. Is there any objection to the admission of let's call it Revised Exhibit MEC-127, which includes Discovery Responses 1a through 1d, MEC Exhibit 128, and MEC-129?

Hearing no objections, those exhibits are admitted.

MR. BZDOK: Thank you. Ms. Braunschweig, I appreciate your time and your answers today, and I have no further questions for you.

JUDGE WALLACE: Do we want to take a few minutes off the record so you can decide if you need to do any redirect, Ms. Durian?

MS. DURIAN: Yes, please, your Honor.

JUDGE WALLACE: O.K. Let's go off the record for about ten minutes.

(Recess from 11:34 a.m. until 11:45 a.m.)

JUDGE WALLACE: All right. Back on the record. Ms. Durian, do you have any redirect for your witness?

MS. DURIAN: Staff has no redirect and requests that the witness be excused from the stand.

JUDGE WALLACE: All right. Thank you

very much, Ms. Braunschweig. You are excused.

(The witness was excused.)

- - -

JUDGE WALLACE: All right. We're going to bind in the rest of this bad boy.

MS. DURIAN: Your Honor.

JUDGE WALLACE: Yes.

MS. DURIAN: Are the Exhibits 17.0, 17.1, and 17.2 admitted into the record?

JUDGE WALLACE: Yes.

MS. DURIAN: Thank you.

JUDGE WALLACE: All right. In no particular order, or in some order that I put it in that's not fathomable in terms of method and madness, Staff goes last, correct?

MS. DURIAN: Yes, your Honor.

JUDGE WALLACE: O.K. And are you handling the bind-in for Staff?

MS. DURIAN: No, your Honor. Michael Orris is handling the bind-in.

JUDGE WALLACE: O.K. I remember you told me that. O.K. All right. Beginning with you, Mr. King.

MR. KING: Thank you, your Honor. Can you hear me all right?

JUDGE WALLACE: Yes.

MR. KING: Great. Pursuant to the stipulation of the parties, the Attorney General moves to bind in the prefiled Direct Testimony of Sebastian Coppola, consisting of a cover page, table of contents, 124 pages of questions and answers, and an appendix A that contains Mr. Coppola's experience and qualifications. Also at this time and pursuant to the stipulation of the parties, the Attorney General moves for the admission of prefiled Exhibits AG-1 through AG-48, which were filed with Mr. Coppola's testimony, as well as hearing room Exhibits AG-49 through AG-64, inclusive, which were uploaded to the SharePoint drive ahead of the hearing for review by the parties. I do note that there are confidential versions of exhibits AG-4, AG-9, AG-10, and AG-52, which will only be served on those parties who have signed the nondisclosure certificate in this case.

JUDGE WALLACE: O.K. Is there any objection to binding in the direct testimony of Mr. Coppola?

Hearing none, the testimony is bound in.

Is there any objection to the admission of Exhibits AG-1 through AG-48, as well as Exhibits AG-49 through AG-64, noting that there are confidential versions of Exhibits AG-4, AG-9, AG-10, and AG-52?

Hearing none, those exhibits are admitted.

(Testimony bound in.)

- - -

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

MPSC Case No. U-21534

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)

Direct Testimony
And Exhibits
of
Sebastian Coppola

On behalf of
Attorney General Dana Nessel

July 26, 2024

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I. Introduction

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.

A. My name is Sebastian Coppola. I am an independent business consultant. My office is at 5928 Southgate Rd., Rochester, Michigan 48306.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.

A. I am a business consultant specializing in financial and strategic business issues in the fields of energy and utility regulation. I have more than forty years of experience in public utility and related energy work, both as a consultant and utility company executive. I have testified in several regulatory proceedings before the Michigan Public Service Commission (MPSC or Commission) and other regulatory jurisdictions. I have prepared and/or filed testimony in rate case proceedings, revenue decoupling reconciliations, gas conservation programs, Gas Cost Recovery (GCR) cases and Power Supply Cost Recovery (PSCR) cases, and other proceedings. As accounting manager and later financial executive for two regulated gas utilities with operations in Michigan and Alaska, I have been intricately involved in regulatory proceedings related to gas cost recovery cases, gas purchase strategies, rate case filings and power plant cost analysis. I have also supported other witnesses in testimony before the MPSC in various rate setting and other regulatory proceedings.

Q. WHAT EXPERIENCE DO YOU HAVE WITH ELECTRIC UTILITIES?

A. I have performed rate case analyses and filed testimony in several electric general rate cases addressing issues on revenue requirement, sales level determination, operations and maintenance expenses, cost allocations, cost of capital, cost of service and rate design, various cost tracking mechanisms and integrated resource plans. In addition, I have performed analyses of power costs and filed testimony in power supply cost recovery mechanisms, including reconciliation of annual power supply costs.

In my position as Senior Vice President of Finance at MCN Energy Group, I had responsibility for project financing of independent power generation plants in which MCN was an owner. In this regard, I was intricately involved and became knowledgeable of PURPA qualified cogeneration plants in Michigan and other states. In addition, I was involved in negotiating the development and financing of power generation and electricity distribution plants in other countries, such as India.

Q. PLEASE LIST SOME OF THE MORE RECENT CASES YOU HAVE PARTICIPATED IN BEFORE THE MPSC AND OTHER REGULATORY AGENCIES.

A. Here is a partial list of the most recent regulatory cases in which I have participated:

- Filed testimony on behalf of the Michigan Attorney General in the Upper Peninsula Power Company (UPPCO) 2024 gas rate case U-21555 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in the Michigan Gas Utilities Corporation (MGUC) 2024 gas rate case U-21540 on several

issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.

- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2024 gas rate case U-21291 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2022-2023 GCR reconciliation in case No. U-21065.
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy (CECo) 2023 gas rate case U-21490 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTM Michigan Lateral Company (DMLC) 2023 Act 9 Transportation Service rate update in case No. U-21525.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2022 PSCR reconciliation in case No. U-21051.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2022-2023 GCR reconciliation case No. U-21067.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022 PSCR reconciliation in case No. U-21049.
- Filed testimony on behalf of the Michigan Attorney General in the Indian Michigan Power Company's 2023 electric rate case U-21461 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2023-2024 GCR plan in case No. U-21271.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023-2024 GCR plan in case No. U-21269.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 electric rate case U-21389 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2023-2024 GCR plan in case No. U-21277.

- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2023 rate case U-21297 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2023-2024 GCR plan in case No. U-21273.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022 gas rate case U-21308 on several issues, including sales revenues, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-2022 GCR plan reconciliation case No. U-20817.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2021 PSCR plan reconciliation case No. U-20827.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2021-2022 GCR plan reconciliation case No. U-20819.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2022 general rate case No. U-21286.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-2022 GCR plan reconciliation case No. U-20823.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022-2023 GCR plan case No. U-21062.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2022-2023 GCR plan case No. U-21070.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022 electric rate case U-21224 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Public Counsel Division of Washington Attorney General in the Avista 2022 electric and gas rate cases on several issues, including operation and maintenance expenses, capital expenditures, and other items.

Appendix A elaborates further on my qualifications in the regulated energy field.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked by the Attorney General to perform an independent analysis of DTE Electric Company's ("Company" or "DTEE") Electric Rate Case filing in Case No. U-21534. This testimony presents a report of that analysis with related recommendations.

Q. WHAT TOPICS ARE YOU ADDRESSING IN YOUR TESTIMONY?

A. I am addressing the following major topics in this case:

1. The level of proposed Rate Base and Capital Expenditures
2. The Company's Cost of Capital
3. Working Capital
4. The level of Operations and Maintenance expenses
5. The Adjusted Revenue Deficiency

The absence of discussion on other matters in my testimony should not be taken as an indication that I agree with those aspects of DTEE's rate case filing. The narrow focus of my testimony is, instead, a consequence of focusing on certain issues within the available resources.

Q. IS YOUR TESTIMONY ON THESE TOPICS ACCOMPANIED BY EXHIBITS?

A. Yes. I am sponsoring the following exhibits, which were either prepared by me or under my direct supervision:

1. Exhibit AG-1 DTE Energy Investor Presentation Information
2. Exhibit AG-2 Blue Chip Report with CPI Rates
3. Exhibit AG-3 Emergent Replacements 2018-2023
4. Exhibit AG-4 CONF EV Utility Make Ready Attachments
5. Exhibit AG-5 Housing Starts

6. Exhibit AG-6 I-375 Relocation
7. Exhibit AG-7 Tree Trim Surge Cost Savings
8. Exhibit AG-8 Steam Generation Actual Capex 2019-2023
9. Exhibit AG-9 CONF Nuclear Plant Security System
10. Exhibit AG-10 CONF Nuclear Plant Radio System
11. Exhibit AG-11 Nuclear Capital Expenditures 2018-2023
12. Exhibit AG-12 Nuclear Project Discovery for Projects $3MM+
13. Exhibit AG-13 Discovery Customer Service IT Projects $3MM+
14. Exhibit AG-14 Discovery IT Project 3MM+
15. Exhibit AG-15 IT Capex 2018-2023
16. Exhibit AG-16 Discovery Corporate Facilities and Projects 3MM+
17. Exhibit AG-17 Corporate Capex 2018-2023
18. Exhibit AG-18 Capex, Rate Base Depreciation, Property Tax Adjustments
19. Exhibit AG-19 Deferred Ludington Costs
20. Exhibit AG-20 Working Capital Adjustment to Deferred Incentive Comp
21. Exhibit AG-21 DTEE Incentive Comp Performance Metric Results
22. Exhibit AG-22 TOD Cost Deferral and Cost Detail
23. Exhibit AG-23 Customer Power Outages from Trees
24. Exhibit AG-24 Detroit Tree Trim Academy Participation
25. Exhibit AG-25 Tree Trim Surge Return on Regulatory Asset
26. Exhibit AG-26 Overall Cost of Capital
27. Exhibit AG-27 Cost of Common Equity-Summary
28. Exhibit AG-28 Cost of Common Equity-DCF
29. Exhibit AG-29 Cost of Common Equity-CAPM
30. Exhibit AG-30 Cost of Common Equity-Risk Premium
31. Exhibit AG-31 Electric ROE Decisions by Regulatory Commissions
32. Exhibit AG-32 Midwest Utilities ROEs
33. Exhibit AG-33 Peer Group Analysis
34. Exhibit AG-34 Market to Book Ratios
35. Exhibit AG-35 Moody’s Cash Flow Coverage Ratio

36. Exhibit AG-36 Value Line Article on Volatility vs. Risk
37. Exhibit AG-37 O&M Adjustments Summary
38. Exhibit AG-38 O&M Inflation Adjustment
39. Exhibit AG-39 O&M Steam Generation
40. Exhibit AG-40 O&M Tree Trim Surge Program Savings
41. Exhibit AG-41 Uncollectible Accounts Expense
42. Exhibit AG-42 O&M Injuries and Damages
43. Exhibit AG-43 O&M Active Health Care
44. Exhibit AG-44 O&M Incentive Compensation
45. Exhibit AG-45 Voluntary Separation Package
46. Exhibit AG-46 Credit Card Information
47. Exhibit AG-47 Corporate Aircraft Costs
48. Exhibit AG-48 Revenue Deficiency Calculation

II. SUMMARY CONCLUSIONS & RECOMMENDATIONS

Q. PLEASE PROVIDE A SUMMARY OF YOUR CONCLUSIONS AND ADJUSTMENTS TO THE COMPANY'S REVENUE DEFICIENCY CALCULATION BEFORE YOU ADDRESS EACH TOPIC IN DETAIL.

A. The Company filed for a base rate increase of $456.4 million. This rate increase represents an overall increase in rates of 8.2%, with a 9.6% increase to residential customers. As a result of the rate case adjustments that I propose in my testimony, I determined that the Company has a revenue deficiency of $139.5 million. Based on this amount of rate increase, the average residential customer should see an increase of approximately 2.5% in their total bill.

It is noteworthy to point out that for the historical test year, the Company reported a revenue excess of $80.5 million.

Based on my analysis of the Company's case, I have reached the following summary conclusions and recommendations:

1. I propose a lower level of Operations and Maintenance expenses of $123.5 million for the test year.
2. Along with other AG witnesses, I have included a reduction in capital expenditures of $1.018 billion and a reduction in rate base of $783.9 million, including a reduction in working capital of $25.7 million, for a reduction in revenue requirement of $60 million.
3. I propose a reduction in depreciation expense of $40.8 million pertaining to the proposed reductions in capital expenditures.
4. I propose a reduction in property tax expense of $12.3 million pertaining to the proposed reductions in capital expenditures
5. I recommend an authorized rate of return on equity of 9.85% in comparison to the Company's proposed ROE rate of 10.50%, for a reduction in the revenue deficiency of $75.5 million.
6. I recommend that the Commission reject the addition of $87 million to the Tree Trimming Surge program for 2025 and reduce the return on the regulatory asset by $8.9 million to reflect a return rate based on the short-term debt.

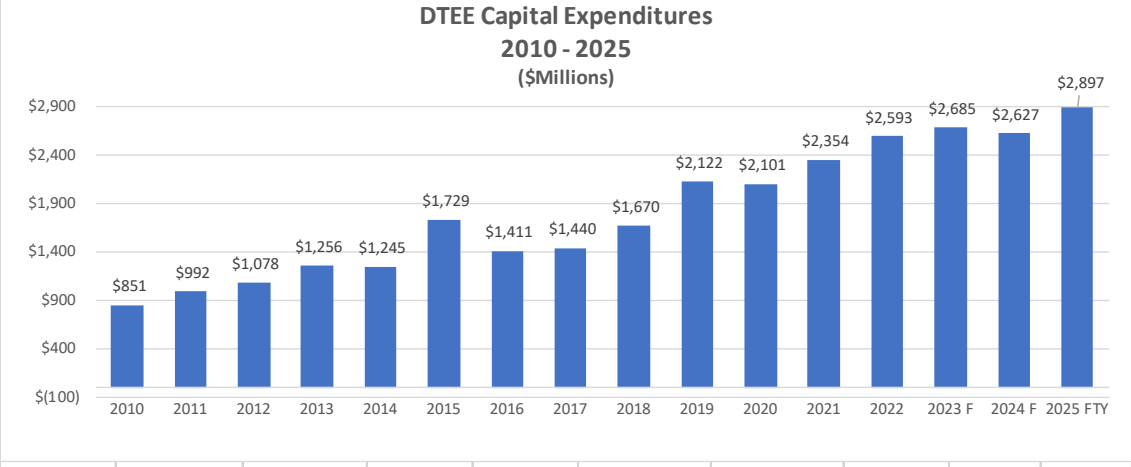
The remainder of my testimony provides further details and support for these summary conclusions and recommendations.

III. LARGE INCREASE IN RATE BASE AND CAPITAL EXPENDITURES

Q. PLEASE DISCUSS YOUR CONCERNS WITH THE LEVEL OF CAPITAL EXPENDITURES PROPOSED BY THE COMPANY AND THE RESULTING INCREASE IN RATE BASE.

A. In this general rate case, DTEE has proposed capital expenditures of $2.7 billion for 2023, $2.6 billion for 2024, and an additional $2.9 billion for 2025, including expenditures under the Infrastructure Recovery Mechanism (IRM). The total proposed capital expenditures over this 36-month period are $8.2 billion.[1] These expenditures follow capital expenditures of $4.9 billion made during the prior two years in 2021 and 2022.[2] The following chart in Table 1 shows the dramatic increase in capital expenditures over recent years, in comparison to more moderate amounts in prior years.

Table 1



[1] Exhibit A-12, Schedule B5 and Exhibit A-33, Schedule X1.
[2] DR AGDE-3.129.

Until 2011, the Company was able to keep capital expenditures below $1 billion annually. Fifteen year later, the level of annual capital expenditures has nearly tripled.

The capital expenditures have fueled an alarming increase in rate base. As shown below in Table 2, rate base has been growing at high-single digit to double digit rates in recent years and the Company is proposing to increase rate base again in this rate case by 16%, to $22.1 billion. The proposed level of rate base in this rate case is more than double the amount of rate base the Company had nearly 10 years ago in 2013.

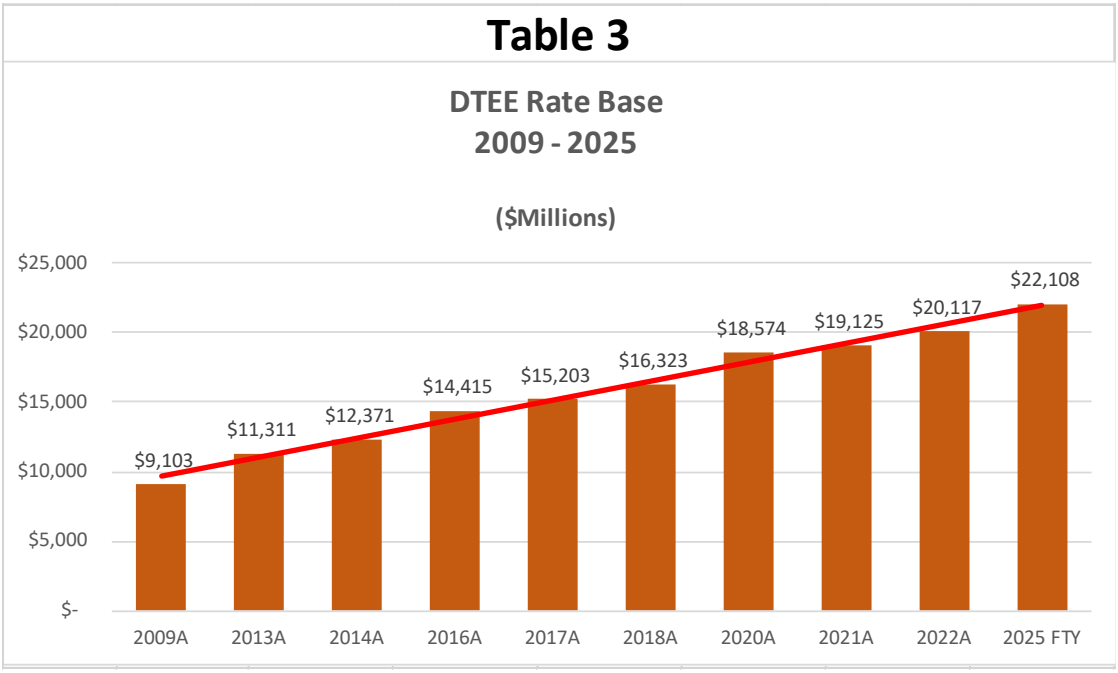
Table 2
DTE Electric Rate Base Growth
2009 to Projected 2025 Test Year

Rate Base Year	2009A	2013A	2014A	2016A	2017A	2018A	2020A	2021A	2022A	2025 FTY
Docket No.	U-16472	U-17767	U-18014	U-18255	U-20162	U-20561	U-20836	U-21297	U-21534	U-21534
Rate Base [1] (Millions)	$ 9,103	$ 11,311	$ 12,371	$ 14,415	$ 15,203	$ 16,323	$ 18,574	$ 19,125	$ 20,117	$ 22,108
Year over Year Change		24%	9%	17%	5%	7%	14%	3%	5%	16%
Cumulative Change over 2009 Rate Base		24%	36%	58%	67%	79%	104%	110%	121%	143%

[1] Historical actual rate base in each docket, except 2025 FTY is a proposed amount.

This significant increase in rate base is illustrated by the following chart included in Table 3, which shows the accelerated trend of increases in recent years. The current trend has significant negative implications for customer bills, as discussed later in my testimony.

Table 3



Q. WHAT DO YOU BELIEVE IS DRIVING THIS DRAMATIC INCREASE IN CAPITAL EXPENDITURES AND RATE BASE SINCE 2009?

A. I believe there are two main drivers. First, replacement of aging infrastructure and new capital spending to address market growth have required an increase in capital expenditures, which have accelerated investment to some degree. The Company continues to propose ever-increasing capital expenditures to replace and rebuild electrical lines, poles, substations, and related facilities. Some of this work is necessary and must be done. However, the Company has also proposed hundreds of millions of dollars in expensive automation projects, digital projects, a dizzying number of pilot projects, information technology projects, and office remodeling that raise questions about priority spending toward more fundamental electrical infrastructure projects.

Prior to 2012, DTEE was able to manage replacement of aging infrastructure and also invest in new facilities to meet market growth within a more reasonable increase in rate base. Therefore, customer growth and replacement of aging infrastructure by themselves do not fully explain the significant increase in capital expenditures and rate base.

Second and perhaps a bigger driver, the replacement of aging electrical infrastructure has given the Company an opportunity to accelerate rate base growth in order to increase earnings growth. For utility companies, earnings growth is directly related to rate base growth. As shown in the tables above, large increases in capital expenditures result in double digit increases in rate base, which in turn fuels earnings growth, dividend growth and stock price appreciation for shareholders.

The Company's parent company, DTE Energy, has been quite clear and aggressive in communicating to investors and securities analysts its goal of increasing operating earnings at the electric utility at an average annual rate of 5% to 7%. Exhibit AG-1 includes pertinent pages from a March 8, 2022 Investor Presentation, which shows this drive to increase earnings through increased capital spending at the utility. It also shows how investors and shareholders have been well rewarded. For a utility such as DTEE with limited sales and revenue growth, the increase in earnings comes almost entirely from the increase in capital expenditures and rate base. The presentation is devoid of any discussion about sales or revenue growth to propel earnings growth at the utility.

Q. DO THE HIGH CAPITAL SPENDING AND OPERATING COST INCREASES SIGNIFICANTLY IMPACT RESIDENTIAL CUSTOMER BILLS?

A. Yes. The Company has proposed to increase residential rates in this rate case by 9.6% over current rates. This increase in annual customer bills poses a significant burden on all residential customers, and especially those with fixed and low income. The compounding effect of large additions to rate base will continue to increase customer rates to unaffordable levels for many customers, particularly those in fixed and lower income brackets. Simply put, this trend is not sustainable for customers. To avoid bill affordability problems in the future, the Company needs to moderate and be more selective in its capital spending in the coming years.

IV. Review of Capital Expenditures

Q. IN YOUR ANALYSIS, HAVE YOU DETERMINED SPECIFIC AREAS WHERE CAPITAL EXPENDITURES COULD BE REDUCED?

A. Yes. I have analyzed the Company's forecasted capital expenditures by major department or functional area and I have identified more reasonable expenditure levels that the Commission should consider.

In projecting adjusted capital expenditures for 2024 and 2025, where applicable I applied an inflation factor to the historical cost base in order to reflect inflationary cost pressure that the Company may face in those years. The inflation factors are 2.4% for 2024 and

2.2% for 2025. These rates reflect the Consumer Price Index-Urban forecast presented in the February 2024 Blue Chip Report.[3]

A. Distribution Plant

As shown on page 1 of Exhibit A-12, Schedule B5.4, the Company forecasted nearly $4.8 billion in capital expenditures for Distribution Plant for the three years 2023 to 2025. After reviewing the testimony of Company witnesses sponsoring testimony in this area, related exhibits, and responses to discovery, I have identified capital expenditure reductions applicable to several capital programs and projects.

1. Emergent Replacements

Q. PLEASE EXPLAIN YOUR ASSESSMENT OF CAPITAL EXPENDITURES FOR EMERGENT REPLACEMENT PROGRAMS.

A. On page 1 of Exhibit A-12, Schedule B5.4, the Company identified three categories of Emergent Replacement Programs: Storm-related, Non-Storm, and Substation Reactive. The total amount of capital expenditures for 2022 for these three programs was $484.7 million. The Company forecasted $531.3 million in capital expenditures for 2023, $492.6 million for 2024, and $506.9 million for 2025. The 2024 amount was reduced by $20.8 million and the 2025 amount was reduced by $21.4 million for expected reductions in emergent capital spending from the anticipated benefit of strategic capital spending.

[3] Exhibit AG-2 includes the February 2024 Blue Chip Report.

The Company arrived at its forecasted level of expenditures for emergent replacement programs by applying retroactive inflation adjustments to historical amounts from 2018 to 2022 and labeling them normalization adjustments on page 3 of Exhibit A-12, Schedule B5.4. It then applied additional forecasted inflation factors for 2023, 2024, and 2025 to the adjusted five-year average cost base to determine the forecasted capital expenditures for the forecasted bridge periods and projected test year. I do not agree with that approach. The Company is simply compounding inflationary increases on top of inflationary increases that already occurred in the historical years.

In response to discovery, the Company disclosed that it inflated 2018 costs by 1.8% for the inflation in 2019 and then again in 2020 by 1.2% for inflation in 2020, and then again by 4.7% for inflation in 2021, and again by 8.0% for inflation in 2022.[4] This process is then repeated for subsequent historical expenditures for 2019 to 2022. This compounding of historical inflation on top of costs that already reflect inflation in the year that the capital expenditures occurred is simply a methodology to increase the base costs on which the Company later adds forecasted inflation for 2023 through 2025. The Company has not provided any evidence that historical costs increased by inflation or by other means in future years. In accepting these compounded inflationary adjustments in recent prior rate cases, the Commission may not have fully understood how the Company had improperly inflated these costs to determine the amount of forecasted capital expenditures included in rate base. However, the Commission should not accept this brazen attempt to inflate

[4] Exhibit AG-3 includes DR AGDE-3.96a and b.

historical capital expenditures by improperly increasing the base on which forecasted costs are calculated in either this or future rate cases.

Although I agree with using a five-year normalization approach to forecast capital expenditures for future years, it should be done using actual capital expenditures from prior years, not by recasting numbers with additional assumed costs that were not incurred based on prior year inflation adjustments. If any inflation was experienced in those prior years, it is reflected in the actual amounts. It is simply an unsupported fabrication to inflate historical costs to arrive at an adjusted historical base and to then further inflate those costs for future years with projected inflation factors. I will also point out that the future inflation rates used by the Company to calculate forecasted Emergent Replacements capital expenditures for 2023, 2024, and 2025 are blended inflation rates consisting of both the CPI and the Company's internal forecasted wage increases. As discussed in more detail in the O&M Expense - Inflation Adjustment section of my testimony, the Commission has previously rejected the use of blended inflation rates.

I will also point out that contrary to the directives by the Commission in Case Nos. U-20561 and U-20836, the Company did not provide an analysis in this rate case of the offsetting effects of significant distribution capital investments on inflationary pressures on Emergent Replacements.

Q. WHAT SPECIFIC ADJUSTMENTS DO YOU RECOMMEND FOR THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR THE EMERGENT CAPITAL PROGRAMS?

A. To calculate an appropriate forecast of capital expenditures for emergent replacement programs for the 2024 and 2025 forecasted periods, I used the five years historical average capital expenditures from 2019 to 2023 and applied the CPI-based future inflation factors. In response to discovery, the Company provided the actual historical capital expenditures for the three categories from 2019 to 2023.[5] Based on this information, I calculated the forecasted capital expenditures for 2024 using the latest average historical average amount spent and adjusting it by the inflation factors of 2.4% for 2024 and 2.2% for 2025.

For the Storm category, the average 5-year spending was $235,956,000. After adjusting for inflation, the forecasted amount is $241,660,000 for 2024 and $246,976,000 for 2025.[6] In comparison, the Company forecasted $244,066,000 for 2024 and $251,144,000 for 2025. Therefore, I recommend that the Commission remove the difference of $2,406,000 for 2024 and $4,168,000 for 2025 from the Company's forecasted capital expenditures.

For the Non-Storm category, the average 5-year spending was $200,008,000. After adjusting for inflation, the forecasted amount is $204,808,000 for 2024 and $209,314,000 for 2025.[7] In comparison, the Company forecasted $220,275,000 for 2024 and

[5] Id.
[6] $235,956,000 x 1.024 = 241,660,000 x 1.022 = $ 246,976,000.
[7] $200,008,000 x 1.024 = 204,808,000 x 1.022 = $ 209,314,000.

$226,663,000 for 2025. Therefore, I recommend that the Commission remove the difference of $15,467,000 for 2024 and $17,349,000 for 2025 from the Company's forecasted capital expenditures.

For the Substation Reactive category, the average 5-year spending was $41,508,000. After adjusting for inflation, the forecasted amount is $42,504,000 for 2024 and $43,439,000 for 2025.[8] In comparison, the Company forecasted $49,057,000 for 2024 and $50,480,000 for 2025. Therefore, I recommend that the Commission remove the difference of $6,653,000 for 2024 and $7,041,000 for 2025 from the Company's forecasted capital expenditures.

Q. WHAT IS THE TOTAL REDUCTION IN CAPITAL EXPENDITURES FOR EMERGENT REPLACEMENTS THAT YOU RECOMMEND?

A. I recommend that the Commission remove $24,526,000 for 2024 and $28,557,000 for 2025 from the Company's forecasted capital expenditures.

2. Customer Connections and New Load Growth

Q. PLEASE PROVIDE YOUR ASSESSMENT OF FORECASTED CAPITAL EXPENDITURES FOR CUSTOMER CONNECTIONS AND LOAD GROWTH PROJECTS.

[8] $41,508,000 x 1.024 = 42,504,000 x 1.022 = $ 43,439,000.

A. On line 9 of page 1 of Exhibit A-12, Schedule B5.4, the Company included forecasted capital expenditures for Customer Connections and New Load of $216,936,000 for 2023, $206,069,000 for 2024, and $218,608,000 for 2025. Beginning on page 22 of his direct testimony, Company witness Brian Hill discusses how he arrived at the forecasted amounts for 2023, 2024, and 2025. There are two issues with the Company's forecasted capital expenditures in this area. First, the Company applied retroactive historical inflation rates to restate the actual historical number for the three years from 2019 to 2022, before applying the future inflation rates to the adjusted three-year historical average spending. This is the same problem discussed above with Emergent Replacements, where the Company improperly inflates actual historical capital expenditures to create a larger cost base on which to add future inflation adjustments. Mr. Hill also used this faulty approach to forecast capital expenditures for Relocations, Electric System Equipment, NRUC and Improvements Blankets, and General Plant, Tools & Equipment.

In his testimony, Mr. Hill states that the three-year average approach he used in this rate case is consistent with the Commission decision in Case No. U-21297. That statement is incorrect. Although the Commission approved the three-year historical average approach I recommended in that rate case, my historical average did not include any restatement of actual capital expenditures with additional historical inflationary adjustments, as Mr. Hill proposes in his testimony and calculations. The Commission should reject the Company's approach as a change to the previously approved methodology and also because it improperly inflates historical costs. As discussed below, in this rate case, I will use the

same approach to forecast customer connections, new load, relocations, and other capital expenditures previously approved by the Commission in Case No. U-21297.

Second, in his testimony Mr. Hill states that the capital expenditures for Customer Connections and New Load include costs for Utility Make Ready (UMR) for upgrading and installing equipment and facilities at customer premises to support Electric Vehicle chargers under the Transportation Electrification Plan. Although Mr. Hill did not identify those expenditures in his testimony or exhibits, in response to discovery the Company reported that in 2022 it incurred $8,552,844 in capital expenditures for UMR before Contributions In Aid of Construction (CIAC).[9] The Company estimates that CIAC are 15% of the amount spent. After CIAC, the Company incurred net expenditures of $6,439,000 for 2022. For 2023, 2024, and 2025, the Company forecasted UMR capital expenditures of $9,531,029, $14,151,715, and $21,491,850, respectively. Adjusted for the 15% CIAC, the net forecasted amounts are $8,101,000, $12,029,000, and $18,651,000 for 2023, 2024, and 2025, respectively. In my testimony below when forecasting the amount of capital expenditures for Customer Connections and New Load, I excluded the UMR expenditures. I will address those capital expenditures as a separate item.

Q. WHAT SPECIFIC ADJUSTMENTS DO YOU RECOMMEND TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR CUSTOMER

[9] Exhibit AG-4 includes DR AGDE-3.90c.

CONNECTIONS AND NEW LOAD GROWTH, EXCLUDING UMR EXPENDITURES?

A. In response to discovery, the Company provided the actual capital expenditures for Customer Connections and New Load for each year 2021 through 2023.[10] The actual amounts are $184,832,000 for 2021, $214,093,000 for 2022, and $214,753,000 for 2023. After removing the net UMR expenditures discussed above for 2022 and 2023, the adjusted capital expenditures are $207,654,000 for 2022 and $206,652,000 for 2023.[11]

Using the above adjusted amounts for 2021-2023, I calculated an average annual spending level for the past three years of $199,713,000. In response to discovery, the Company also provided the number of customer connections installed by year from 2021 to 2023 and forecasted for 2024 and 2025. The data shows the number of customer connections declined from 21,280 in 2021 to 18,854 in 2022, and then a further decline to 17,555 in 2023. During the three-year period, the Company installed 19,230 customer connections on average, annually, at an average cost of $10,385 per installation.

For 2024 and 2025, the Company forecasted that the number of customer connections would increase by approximately 10% to 19,268, from 17,555 in 2023.[12] The forecasted number of connections for 2024 and 2025 do not reflect the current economic environment

[10] Exhibit AG-5 includes DR AGDE-3.95a and c with attachments.
[11] $214,093,000 - $6,439,000 = $207,654,000 for 2022; $214,753,000 - $8,101,000 = $206,652,000 for 2023.
[12] Id. includes DR AGDE-3.117.

of high interest rates that has dampened new construction. In response to discovery, the Company reported that the number of housing starts in Michigan is forecasted to decline by 3.8% in 2024 after declining by 6% in 2023. Housing starts in 2025 are forecasted to increase by 10.8% from the lower level in 2024. This is the best information we have to forecast customer connections for 2024 and 2025. Based on this information, I forecasted customer connections of 16,888 for 2024 and 18,712 for 2025.[13]

Using the $10,385 historical average cost per installation and adjusting it for inflation and then multiplying by the forecasted number of units, I calculated the forecasted capital expenditures for Customer Connections and New Load at $179,587,000 for 2024 and $203,362,000 for 2025.[14] In comparison, the Company forecasted capital expenditures of $194,040,000 for 2024 and $199,957,000 for 2025 after removing the UMR net capital expenditures.[15]

Therefore, I recommend that the Commission remove the difference of $14,453,000 from the Company's forecasted 2024 capital expenditures and increase the 2025 forecasted capital expenditures by $3,405,000.

Q. PLEASE DISCUSS THE ADJUSTMENTS YOU PROPOSE FOR UMR EXPENDITURES FOR 2024 AND 2025.

[13] 2024: 17,555 in 2023 x (1 – 3.8%) = 16,888. 2025: 16,888 x 1.108 = 18,712.
[14] 2024: $10,385 x 1.024 = $10,634 x 16,888 = $179,587,000. 2025: $10,634 x 1.022 = $10,868 x 18,712 = $203,362,000.
[15] 2024: 206,069,000 - $12,029,000 = $194,040,000. 2025: $218,608,000 – 18,651,000 = $199,957,000.

A. As discussed above, the Company forecasted Utility Make Ready capital expenditures, net of CIAC, of $12,029,000 for 2024 and $18,651,000 for 2025. These forecasted amounts are based on the premise that more customers, both residential and non-residential, will buy electric vehicles and will require modifications and additions to their electrical facilities to accommodate Level 2 and faster chargers. The forecasted net capital expenditures for 2024 and 2025 represent increases of 87% and 190% over 2022 actual net UMR expenditures, and 48% and 130% increases over the 2023 net UMR capital expenditures. These are very large increases in capital spending that are not reflective of the current market environment with EV sales.

During the first six months of 2024, EV manufacturers have realized that electric vehicles are not selling at the pace anticipated as late as 2023 and EVs are stockpiling at dealers' lots. EV buyers often have been dissatisfied with the actual driving range, particularly during the winter and hot days that quickly drain the car batteries. Reliability of certain vehicles with recalls for software and equipment failures has also created customer dissatisfaction and increased concerns and fear with prospective EV buyers. EV manufactures have cut back production of EVs, delayed new models, deferred building new batteries plants, and redirected resources to hybrid vehicles with batteries that self-charge during gasoline-fueled operation.[16] The current environment and demand for EVs

[16] Information gathered from recent articles in the Wall Street Journal, the Detroit News, and other publications.

does not support the increase in spending forecasted by the Company for 2024 and 2025 for UMR.

With EV adoption currently waning, I propose that the 2024 and 2025 capital expenditures for UMR be set at the 2023 amount plus inflation. It is best to be conservative during this time of uncertainty in EV purchases, to avoid having the Company earning on rate base additions plus recovering depreciation expense on costs that are not likely to materialize. If the Company actually spends more than I propose, it can recover those additional costs in the next rate case. This means forecasted net capital expenditures of $8,295,000 for 2024 and $8,478,000 for 2025 after CIAC.[17] In comparison, the Company forecasted net UMR expenditures of $12,029,000 for 2024 and $18,651,000 for 2025.

Therefore, I recommend that the Commission remove the difference of $3,734,000 for 2024 and $10,173,000 for 2025 from the Company's forecasted capital expenditures.

3. Relocations

Q. PLEASE PROVIDE YOUR ASSESSMENT OF FORECASTED CAPITAL EXPENDITURES FOR LINE RELOCATION PROJECTS.

A. On page 7 of Exhibit A-12, Schedule B5.4, the Company included forecasted capital expenditures for Relocations (Net of CIAC) of $45,618,000 for 2023, $50,480,000 for 2024. and $34,219,000 for 2025. Included in those amounts are capital expenditures for

[17] 2024: 2023 net UMR expenditures of $ 8,101,000 x 1.024 = $8,295,000. 2025: $8,295,000 x 1.022 = $8,478,000.

the I-375 relocation project of $5,938,000, $25,000,000, and $8,000,000 for 2023, 2024, and 2025, respectively. I will address this project separately from the more routine relocation projects. Excluding the I-375 project, the forecasted capital expenditures are $39,680,000 for 2023, $25,480,000 for 2024, and $26,210,000 for 2025. Based on the historical expenditures for routine relocations, I find the Company's forecasted amounts for 2024 and 2025 to be reasonable and I do not propose any adjustments.

Q. WHAT ADJUSTMENTS DO YOU PROPOSE FOR THE I-375 RELOCATION PROJECT?

A. On pages 25 and 26 of his direct testimony, Mr. Hill dedicates 8 lines of testimony to explain the I-375 relocation project with a total cost of $39 million. Mr. Hills states that the Company was notified by the Michigan Department of Transportation (MDOT) that the state plans to restructure the I-375 below-ground freeway into a grade level boulevard in 2025, which will require relocation of electrical lines. He also stated that work was to begin in 2023, with most of the work occurring in 2024 and finishing in 2025. As stated above, the Company forecasted capital expenditures of $5,938,000, $25,000,000, and $8,000,000 for 2023, 2024, and 2025, respectively.

In discovery, the Attorney General asked the Company to provide the timeline for each phase of the project and identify the phase the project was currently in. The discovery also requested that the Company provide the latest project schedule from MDOT showing the project start and completion dates. In response, the Company reported that the Relocation

phase of the project is currently in the engineering and design phase and work has begun to prepare contractor bid requests with construction currently planned for late 2024 and into the end of 2025. The second phase of the project for New Infrastructure installation has not begun and project scoping is planned for the fourth quarter of 2024 and conceptual analysis in the third quarter of 2025. The Company also reported that it has not received a project schedule from MDOT and has only received a notice to vacate.[18]

This last piece of information is very telling. It shows that MDOT has not set a firm schedule for the project. MDOT is known for establishing initial plans and later delaying projects. Although the Company may have done some design and engineering work in 2023 with the $5.9 million budgeted, it is unlikely that it will spend the $25 million forecasted for 2024 or the $8 million forecasted for 2025. It is premature and imprudent to include those large amounts in rate base in this rate case. The Company would be earning a return and recovering depreciation expense for costs that would likely not be incurred. Therefore, I recommend that the Commission remove the $25 million for 2024 and the $8 million for 2025 from the Company's forecasted capital expenditures.

4. Electric System Equipment

Q. PLEASE ASSESS THE COMPANY'S PROPOSED CAPITAL EXPENDITURES FOR ELECTRIC SYSTEM EQUIPMENT.

[18] Exhibit AG-6 includes DR AGDE-3.91b and e.

A. On page 1 of Exhibit A-12, Schedule B5.4, the Company shows forecasted capital expenditures for Electric System Equipment of $33,655,000 for 2023, $33,300,000 for 2024, and $34,266,000 for 2025. According to Mr. Hill's direct testimony, the Company inflated the actual historical capital expenditures to arrive at its forecasted capital expenditures for the forecasted years. As discussed above, this approach is inappropriate as it unfairly increases costs to customers and should be rejected by the Commission.

In line with previously established practices approved by the Commission, I calculated the average capital expenditures for this capital program category for the three years 2021 to 2023 based on actual expenditures provided by the Company.[19] The Company spent $30,471,000 in 2021, $30,180,000 in 2022, and $27,670,000 in 2023 with an average annual amount of $29,440,000. After adjusting this amount for inflation, I calculated the 2024 forecasted capital expenditures at $30,147,000 and 2025 expenditures at $30,810,000.[20] These amounts are below the Company's forecasts by $3,153,000 for 2024 and $3,456,000 for 2025. I recommend that the Commission remove these amounts from the Company's forecasted capital expenditures.

5. General Plant, Tools, Equipment & Miscellaneous Items

Q. PLEASE ASSESS THE COMPANY'S PROPOSED CAPITAL EXPENDITURES FOR GENERAL PLANT, TOOLS, EQUIPMENT & MISCELLANEOUS ITEMS.

[19] Exhibit AG-5 includes DR AGDE-3.95a with attachment.
[20] Three-year average amount x 1.024 for 2024 x 1.022 for 2025.

A. On page 1 of Exhibit A-12, Schedule B5.4, the Company shows forecasted capital expenditures for General Plant, Tools, Equipment & Miscellaneous Items of $5,866,000 for 2023, $9,144,000 for 2024, and $9,410,000 for 2025. According to Mr. Hill's direct testimony, the Company inflated the actual historical capital expenditures to arrive at its forecasted capital expenditures for the forecasted years. As discussed above, this approach is inappropriate, unfairly increases costs to customers, and should be rejected by the Commission.

In line with previously established practices approved by the Commission, I calculated the average capital expenditures for this capital program category for the three years 2021 to 2023 based on actual expenditures provided by the Company.[21] The Company spent $7,445,000 in 2021, $8,103,000 in 2022, and $6,090,000 in 2023 with an average annual amount of $7,213,000. After adjusting this amount for inflation, I calculated the 2024 forecasted capital expenditures at $7,386,000 and 2025 expenditures at $7,548,000.[22] These amounts are below the Company's forecasts by $1,758,000 for 2024 and $1,862,000 for 2025. I recommend that the Commission remove these amounts from the Company's forecasted capital expenditures.

[21] Exhibit AG-5 includes DR AGDE-3.95a with attachment.
[22] Three-year average amount x 1.024 for 2024 x 1.022 for 2025.

6. Portable Generators

Q. PLEASE ASSESS THE COMPANY'S PROPOSED CAPITAL EXPENDITURES FOR PORTABLE GENERATORS.

A. On page 23 of his direct testimony, Mr. Hill briefly discusses the Company's plan to supply backup portable generators to certain customers during extended power outages. On line 28 of page 13 of Exhibit A-12, Schedule B5.4, the Company included $4.5 million of capital expenditures for the generators. In discovery, the Attorney General asked the Company to provide a few more pertinent details on this idea, such as the number of generators that would be purchased, who would qualify to receive them, how the generators would be connected to appliances, who would deliver and retrieve them, how they would be fueled, who would pay for the fuel, etc.

In response, the Company stated for anticipated power outages longer than 48 hours (2 days), the Company would identify a list of customers who would qualify to receive a portable generator with vulnerable customers prioritized. The Company's plan is to have available about 3,700 generators with 3,250 rated at 2200 Watt and 500 at 5000 Watt. The generators would be connected to certain appliances by an extension cord. No connections would be made to heating furnaces or air conditioners due to their hard-wired connections to circuit breakers and because the amperage requirements for air conditioners exceed the generator's capacity. The generators would be fueled with gasoline supplied by Company

employees or contractors. Non-field Company employees would deliver and retrieve the generators.[23]

Although the idea may seem appealing on the surface, it is fraught with pitfalls. The vulnerable customers that the Company aims to help need heat and air conditioning during periods of cold weather and hot days when the worst storms usually occur. The generators would not be able to help with either of those life-threatening needs. It is also not clear what those customers would do for the first two days until the generators are delivered. With tens of thousands of customers usually out of power for multiple days, the demand would overwhelm the small supply of generators, thus causing more customer ill will than appreciation. Gasoline delivery could be compromised if nearby gas stations also do not have power to operate their pumps.

If the Company believes there is merit and corporate image building benefits to such an idea, it should fund it with shareholder money. It is unfair for customers who pay the Company for electricity service, which they are not getting during power outages, to on top of that pay for backup generators through rates, which also may provide them with no service. I recommend that the Commission remove the $4.5 million from the Company's forecasted capital expenditures for 2024.

[23] DR AGDE-3.93a-f.

7. Tree Trimming Prioritization Model and Cost Savings

Q. PLEASE DISCUSS THE REDUCTIONS IN CAPITAL EXPENDITURES YOU PROPOSED RELATED TO THE TREE TRIMMING SURGE PROGRAM AND THE RISK PRIORITIZATION MODEL.

A. As discussed under the Working Capital section of my testimony, the Company proposed undertaking a Tree Trim Risk Prioritization Modeling approach, with also purchasing LiDAR technology, without first performing a cost/benefit analysis that demonstrated such a program would be economically justified. On page 17, line 24 of Exhibit A-12, Schedule B5.4, the Company included capital expenditures for this program of $3,078,000 in 2022 and $3,824,000 for 2023, for a total amount of $6,902,000. This capital spending is not justified and should be removed. I recommend that the Commission disallow the $6,902,000 from rate base in this rate case and also in future rate cases.

Additionally, in response to discovery, the Company reported that its tree trimming and surge program will achieve annual cost savings in capital spending of $66.9 million in 2024 and $59.6 million in 2025.[24] The Company did not include these capital spending savings in the capital expenditures exhibits or in rate base. The only reductions to capital expenditures that the Company reflected in the capital expenditures exhibits is on line 6 of page 1 of Exhibit A-12, Schedule B5.4 for Emergent Replacement Reductions from Strategic Spending and not from the tree trimming program. Therefore, I recommend that

[24] Exhibit AG-7 includes DR AGDE-4.167.

the Commission reduce the Company's forecasted capital expenditures for 2024 and 2025 by $66.9 million and $59.6 million, respectively.

In total for the tree trimming related programs, I recommend that the Commission remove $3,078,000 for 2022, $3,824,000 for 2023, $66,900,000 for 2024, and $59,600,000 for 2025. The O&M portion of the savings will be addressed in the Operations and Maintenance section of my testimony.

8. Electric Distribution 2023 Projects Underspent

Q. PLEASE DISCUSS THE AMOUNT OF FORECASTED 2023 CAPITAL EXPENDITURES IN THE DISTRIBUTION AREA THAT THE COMPANY UNDERSPENT.

A. In discovery, the Attorney General asked the Company to report on the actual amount of capital expenditures incurred in 2023 in the Electric Distribution area. The information provided in response to the discovery request shows that for 2023 the Company incurred actual capital expenditures for Base Capital Programs of $806,973,000.[25] In comparison, the Company forecasted $832,175,000 for the year. The difference of $25,202,000 should be removed from rate base in this rate case. The Company should not be earning a return or receive revenue to cover depreciation expense for costs that it did not incur.

[25] DR AGDE-3.95a with Attachment.

The Commission has previously ruled that underspent amounts included in projected rate base should be removed. Therefore, I recommend that the Commission continue that practice and remove the $25,202,000 from rate base in this rate case.

B. Power Generation- Fossil Fuel Plant Projects

Q. PLEASE EXPLAIN WHAT ADJUSTMENTS YOU PROPOSE TO THE COMPANY'S PROJECTED CAPITAL EXPENDITURES FOR POWER GENERATION FACILITIES.

A. On page 3 of Exhibit A-12, Schedule B5.1, the Company forecasted Routine capital expenditures in the Power Generation area of $274 million for 2023, $273.8 million for 2024, and $192.4 million for 2025. In my review of the proposed expenditures, I identified two adjustments, which I discuss below.

1. Greenwood and Belle River Plants

Q. PLEASE DISCUSS THE CAPITAL EXPENDITURE ADJUSTMENTS THAT YOU PROPOSE FOR THE GREENWOOD AND BELLE RIVER PLANTS.

A. In response to discovery, the Company provided the actual routine capital expenditures by plant site for each year 2021 to 2023. The information provided shows that for the Greenwood plant, capital expenditures averaged $9,992,000 during this three-year

period.[26] For the five-year period from 2019 to 2023, the average spending amount is even less at $9,436,000. In comparison, for 2024 and 2025, capital expenditures were forecasted by the Company to nearly double to $18,817,000 and $18,680,000, respectively. Routine capital expenditures are typically consistent and repetitive. The direct testimony and exhibits sponsored by Company witness Margaret Guillaumin identify certain projects that the Company plans for 2024 and 2025 but there is insufficient justification why the number of projects and amount of forecasted capital expenditures needs to double after only a year, from the actual spending level in 2023.

To develop a reasonable forecast, I applied the rate of inflation for 2024 and 2025 to the average amount of $9,992,000 spent during the most recent three years, to arrive at the 2024 forecast of $10,232,000 and $10,457,000 for 2025. These amounts are lower than the Company's forecasted amount of $18,817,000 for 2024 and $18,680,000 for 2025. The difference is $8,585,000 in 2024 and $8,223,000 for 2025. I recommend that the Commission remove these amounts from the Company's forecasted capital expenditures.

Similarly, for the Belle River plant, the three-year average capital spending during 2021 to 2023 was $44,609,000. After applying inflation to this amount, I calculated 2024 capital expenditures of $45,680,000 for 2024 and $46,685,000 for 2025. The Company forecasted capital expenditures of $58,950,000 for 2024 and $42,757,000 for 2025. The reduction in spending in 2025 appears reasonable. However, the large difference in spending of

[26] Exhibit AG-8 includes DR AGDE-3.111 with attachment.

$13,270,000 for 2024 is not reasonable or justified and the Commission should remove it from the Company's forecasted capital expenditures.

2. Power Generation 2023 Projects Underspent

Q. PLEASE DISCUSS THE AMOUNT OF FORECASTED 2023 CAPITAL EXPENDITURES IN THE FOSSIL GENERATION AREA THAT THE COMPANY UNDERSPENT.

A. In discovery, the Attorney General asked the Company to report on the actual amount of capital expenditures incurred in 2023 in the Power Generation area. The information provided in response to the discovery request shows that for 2023 the Company incurred actual capital expenditures of $450,247,000.[27] In comparison, the Company had forecasted $454,198,000 for the year. The difference of $3,951,000, which should be removed from rate base in this rate case. The Company should not be earning a return or receive revenue to recover depreciation expense for costs that it did not incur.

C. Nuclear Generation- Capital Projects

Q. PLEASE EXPLAIN WHAT ADJUSTMENTS YOU PROPOSE TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES IN THE NUCLEAR POWER GENERATION AREA.

[27] Id. includes DR AGDE-3.107 with attachment.

A. On page 1 of Exhibit A-12, Schedule B5.3, the Company forecasted capital expenditures in the Nuclear Generation area of $266.7 million for 2023, $184.8 million for 2024, and $215.9 million for 2025. The capital expenditures include both routine and non-routine projects, plus the cost of nuclear fuel. In my review of the proposed expenditures, I identified several adjustments, which I discuss below.

1. Security System Computer

Q. PLEASE DISCUSS THE CAPITAL EXPENDITURE ADJUSTMENTS THAT YOU PROPOSE FOR THE SECURITY SYSTEM COMPUTER PROJECT.

A. On line 4 of page 2 of Exhibit A-12, Schedule B5.3, the Company shows capital expenditures for the security computer system of $7,080,000 in 2022, $17,610,000 for 2023, and $9,197,000 for 2024 for a total amount of $33,887,000 over the three-year period.

To assess the reasonableness and prudency of the capital spending for this project, in discovery the Attorney general asked the Company to provide the initial estimated cost of the project with the implementation timeline, the current forecasted cost of the project from inception to completion by year, the current implementation timeline, and explanations of project cost variances of 10% or greater, along with bid information from outside contractors and equipment vendors.

In response the Company provided two Appropriation Request documents with approval dates of January 26, 2023 and June 26, 2024. The documents show that the initial amount requested for project approval was $9,948,000, and that amount was increased to $25,174,000 on January 26, 2023, with a project in-service date of December 29, 2023. No explanation was provided as to why the project cost increased by more than $15 million. The Appropriation Request document includes a description stating that this additional amount would be spent on engineering, system vendor design, fabrication, and some installations and upgrades.

The second document shows an additional increase in cost of $14 million for a new total project cost of $39,173,000, with an in-service date of December 29, 2024. The description provided on the document repeats the explanation from the previous month and adds a list of additional equipment and functions.[28] However, it provides no clear explanation why these additional tasks and requirements were being added in June 2024, three years after the project start date of May 2021. The Company's responses to the discovery questions discuss only project cost changes from rate case to rate case in broad and general terms without providing insight into the total current cost of the project versus the initial approval amount, as was requested.

The initial project cost of $9,948,000 has now mushroomed to $39,173,000, for an increase of $29,225,000. This increase is an excessive cost overrun and reflects an imprudent and

[28] Exhibit AG-9 CONF includes DR AGDE-3.98a-d with the Appropriation Request documents.

unreasonable approach to project cost management. Although some cost increases can be expected with certain projects from time to time due to unexpected problems that may occur, a reasonable expectation for cost increases should not exceed 10% of the project cost. Applying that percentage to the original project cost of $9,948,000 results in a maximum project cost of $10,943,000. The $39,173,000 total cost of the project exceeds that amount by $28,230,000. It would be unfair and unreasonable to burden customers with that excess cost. Therefore, I recommend that the Commission remove that amount from this rate case, with $9,197,000 removed from the Company's forecasted 2024 capital expenditures and the remainder of $19,033,000 from 2023 and prior years.

2. Plant Radio System

Q. PLEASE DISCUSS THE CAPITAL EXPENDITURE ADJUSTMENTS THAT YOU PROPOSE FOR THE PLANT RADIO SYSTEM REPLACEMENT PROJECT.

A. On line 5 of page 2 of Exhibit A-12, Schedule B5.3, the Company shows capital expenditures for the radio system replacement project of $4,176,000 in 2022, $6,050,000 for 2023, and $1,498,000 for 2024, for a total amount of $11,724,000 over the three-year period.

To assess the reasonableness and prudency of the capital spending for this project, the Attorney General asked the Company to provide the initial estimated cost of the project with the implementation timeline, the current forecasted cost of the project from inception to completion by year, the current implementation timeline, and explanations of project

cost variances of 10% or greater, along with bid information from outside contractors and equipment vendors.

In response the Company provided two Appropriation Request documents. The first document has an approval date of October 28, 2022 and the second document has no approval or preparation date. The documents show that the initial amount requested for project approval was $6,000,000, with that amount increasing to $15,815,000 on October 28, 2022, with a project in-service date of December 31, 2023. No explanation was provided for why the project cost increased by more than $9.8 million, other than a description that this additional amount would align with the "8+4 2022 forecast."

The second document shows an additional increase in cost of $3,615,000, for a new total project cost of $19,430,000, with an in-service date of December 31, 2024. The description provided on the document states that the additional costs were incurred due to delays caused by plant conditions that impacted personnel availability and discovery of legacy issues with undersized wiring.[29] As I pointed out above, no approval for this additional spending is shown on the Appropriation Request document. From the document it is not clear why the legacy issues were discovered this late in the process, which is at least three years after the project start date of January 2019, or why availability of plant personnel was an issue that would increase project costs. The Company's responses to the discovery questions discuss only project cost changes from rate case to rate case in broad

[29] Exhibit AG-10 CONF includes DR AGDE-3.99a-d with the Appropriation Request documents.

and general terms, without providing insight into the total cost of the project now versus the initial approval amount, as requested.

What we know is that the initial project cost of $6,000,000 has now increased by $13,430,000, to $19,430,000. This increase is another excessive cost overrun and reflects an imprudent and unreasonable approach to project cost management. Although some cost increases can be expected due to unforeseen problems that may occur in the implementation phase of the project, a reasonable expectation for cost increases should not exceed 10% of the project cost. Applying that percentage to the original project cost of $6,000,000 results in a maximum project cost of $6,600,000. The $19,430,000 total cost of the project exceeds that amount by $12,830,000. It would be unfair and unreasonable to burden customers with that excess cost. Therefore, I recommend that the Commission remove that amount from this rate case, with $1,498,000 removed from the Company's forecasted 2024 capital expenditures and the remaining amount of $11,332,000 from 2023 and prior years.

3. Nuclear Fuel

Q. PLEASE DISCUSS THE CAPITAL EXPENDITURE ADJUSTMENTS THAT YOU PROPOSE FOR NUCLEAR FUEL COSTS.

A. On lines 5 through 10 of page 1 of Exhibit A-12, Schedule B5.3, the Company shows capital expenditures for nuclear fuel of $135,077,000 for 2025. This amount exceeds the cost of nuclear fuel of $110,008,000 in 2023 from the Company's previous refueling

session by approximately $15 million. In discovery, the Attorney General asked the Company to explain how the fuel costs for the 2025 projected test year were determined and why they increased significantly from 2023. The Company was also asked to provide the historical fuel costs incurred annually from 2018 to 2023.

In the response, the Company discusses variances in the number of fuel assemblies from outage to outage without addressing specifically the cost variance between 2023 and 2025, and states the calculation is in accordance with industry accepted software and rules, without providing further explanation or support for the calculation.[30] The bottom line is that the cost increase is not adequately explain or supported.

Based on the historical information provided by the Company, nuclear fuel costs were $120,112,000 in 2021 and $110,008,000 in 2023.[31] The average cost for the two years is $115,060,000. The $135 million forecasted for 2025 is $20 million more than the amount spent on average over the last two refueling periods.

It is also noteworthy to point out that in Case No. U-20836, the Company forecasted that it would spend $122,703,000 for nuclear fuel in 2021 but actually spent $120,112,000. For 2023, the Company forecasted $117,421,000 for 11 months of costs for nuclear fuel, which annualized means it had forecasted $128,100,000 for the entire year. The actual amount for 2023 was $110,008,000, or $7.4 million lower than the 11 months forecast and

[30] Exhibit AG-11 includes DR AGDE-3.102b.
[31] Id. includes DR AGDE-3.102a with attachment.

$18 million lower than the full 12 months forecasted for the year. This historical perspective shows that the Company has a propensity to overestimate the cost of nuclear fuel.

The 2025 nuclear fuel cost is out of line with historical levels by a least $20,017,000. Therefore, I recommend that the Commission remove this amount from the Company's forecasted capital expenditures for 2025.

4. Nuclear Capital Projects

Q. PLEASE DISCUSS THE CAPITAL EXPENDITURE ADJUSTMENTS THAT YOU PROPOSE FOR VARIOUS LARGE NUCLEAR PLANT PROJECTS.

A. On pages 3 and 4 of Exhibit A-12, Schedule B5.3, the Company listed several projects with related capital expenditures and provided the in-service dates. For projects in size of $3 million and greater, the Attorney General requested the Company to provide additional information for each project, why it was necessary, and to provide the project phases with a timeline and the current phase of the project along with other relevant information.

In response, the Company referenced information previously provided in Attachment 9 to the Part III Supplemental filing and to discovery responses submitted to other parties. However, the information requested was not in the referenced Part III documents or in the other discovery responses. In the response, the Company also stated that the Nuclear Generation department does not categorize projects in phases of development and simply

dismissed the request.[32] The response is at odds with common project management practices. Projects typically have phases of development that start with project concept and scoping of project needs, followed by engineering design, project bidding to contractors, construction, and completion. In this case, either the Nuclear department is reluctant to disclose that information or is following an unorthodox project management approach. In either case, the Company's response does not inspire confidence that some of the larger projects listed on pages 3 and 4 of Schedule B5.3 are eligible for inclusion in rate base in this rate case.

Specifically, for the three projects on lines 59, 60, and 61 of page 3 of Schedule B5.3: Natural Draft Cooling Towers, Document Management System Enhancements, and Remote Monitoring, the Company should have identified project phases and timelines with a completion in-service date. The Company has failed to do so and the forecasted capital expenditures remain unsupported. These projects have total capital expenditures of $23,980,000 for 2025. The Company has not made an adequate effort to justify these projects for inclusion in rate base in this rate case. Therefore, I recommend that the Commission remove the total capital expenditures amount of $23,980,000 from the Company's forecasted capital expenditures.

Similarly, on page 4 of Schedule B5.3, the Company shows 4 projects with an in-service date of 2026. These projects are on lines 1, 10, 16, and 26. The projects will not be

[32] Exhibit AG-12 includes DR AGDE-3.103a and b.

completed before the end of the projected test year and will not be used and useful in 2025. Therefore, the total amount of capital expenditures for 2024 of $58,039,000, and $25,874,000 for 2025, should be removed from this rate case. The project on line 28 for the Sanitary System Replacement should have a project plan and timeline with a stated completion date and in-service date. The "Annual" in-service date designation by the Company would imply an annual program, which does not appear to be correct for this project. The Company's inability or unwillingness to provide a project timeline and current phase of development makes it impossible to accept the 2025 capital expenditures of $6,457,000 for inclusion in rate base in this rate case.

Therefore, in total, I recommend that the Commission remove capital expenditures of $58,039,000 for 2024 and $56,311,000 for 2025 from the Company's forecasted capital expenditures.

D. Information Technology Projects

Q. PLEASE DISCUSS THE ADJUSTMENTS THAT YOU PROPOSE TO CAPITAL EXPENDITURES FOR INFORMATION TECHNOLOGY (IT) PROJECTS PROPOSED BY THE COMPANY.

A. Both Company witnesses Michael Hatsios and Pankaj Sharma propose capital expenditures for IT projects. Mr. Hatsios focuses on Customer Service-related projects and Mr. Sharma on other IT projects. I will discuss cost disallowances pertaining to projects proposed by each witness.

With regard to the Customer Service IT projects of $3 million and greater included in Exhibit A-12, Schedule B5.7.3, the Attorney General asked the Company in discovery to provide a project description, statement of necessity, and a project development timeline with the current phase of the project identified among other pertinent information. In response, the Company identified certain projects with capital expenditures included in 2024 and 2025 where no work has yet been started or the project is in the early phase of development. This is the case for the four projects on lines 4, 11, 15, and 18 of Schedule B5.7.3.

The four projects are (1) the MIGP Customer Requested Renewable Energy Project, which will not kick-off until August 2024; (2) the MIGP Scope Billing and Enrollment project, which will not be completed until 2026; (3) the Rider 17-MIGreenPower Residential and Commercial projects, which are still in the early design phase or will not kick-off until 2025; and (4) the 2025 Advance Analytics Use Cases for Reducing MPSC Complaints, which will not start until March 2025.[33] The total capital expenditures for the four projects are $5,750,000 for 2024 and $15,393,000 for 2025.

Given that these projects have not yet started the initial scoping phase, are in the early phase of development, or will not be completed by the end of the projected test year, it is premature to include the forecasted capital expenditures in rate base. Therefore, I

[33] Exhibit AG-13 includes DR AGDE-3.114a-d.

recommend that the Commission remove the $5,750,000 and the $15,393,000 from the Company's forecasted capital expenditures for 2024 and 2025, respectively.

Q. PLEASE DISCUSS THE ADJUSTMENTS THAT YOU PROPOSE TO CAPITAL EXPENDITURES FOR IT PROJECTS SPONSORED BY MR. SHARMA.

A. In discovery, the Attorney General made the same request of the IT projects sponsored by Mr. Sharma in Exhibit A-12, Schedule B5.7.1, as described above for Customer Service projects of $3 million and greater. The request was for the Company to provide a project description, statement of necessity, and a project development timeline with the current phase of the project identified, among other pertinent information.

In response, the Company provided references to pages of Mr. Sharma's testimony for project descriptions and necessity with a further reference to the project charter in Exhibit A-24, Schedule N1. Although the referenced sources provide some of the requested information, they do not provide all the requested information. More concerning is the Company's dismissal of the request to provide the project phases with related timeline and the current phase of the project. Instead, the response to DR AGDE-3.123b provides what appear to be generic weekly and monthly project deadlines.[34] This is not the information requested and it is dissimilar to the information provided by the Company for Customer

[34] Exhibit AG-14 includes DR AGDE-3.123a-d.

Service IT projects discussed above and shown on pages 2 and 3 of DR AGDE-3.114b (Exhibit AG-13).

In Schedule B5.7.1, there are two projects with capital expenditures in excess of $3 million. The first project is on line 9 for Cloud Health and Safety, with capital expenditures of $2,518,000 in 2024 and $582,000 in 2025. The second project is on line 16 for Enhanced Document Management Capability Projects, with capital expenditures of $1,218,000 in 2024 and $2,958,000 in 2025. Given the lack of information, it is not possible to determine what phase those projects are currently in or whether they will be completed by the end of the projected test year and be used and useful.

Therefore, I recommend that the Commission remove the $1,218,000 for 2024 and $2,958,000 for 2025 from the Company's forecasted capital expenditures.

Q. PLEASE DISCUSS THE AMOUNT OF FORECASTED 2023 IT CAPITAL EXPENDITURES THAT THE COMPANY UNDERSPENT.

A. In discovery, the Attorney General asked the Company to provide the actual amount of capital expenditures incurred in 2023 in the Information Technology area. The information provided in response to the discovery request shows that for 2023 the Company incurred actual capital expenditures of $127,456,000.[35] In comparison, the Company had forecasted $162,310,000 for the year in Exhibit A-12, Schedule B5.7. The

[35] Exhibit AG-15 includes DR AGDE-3.122 with attachment.

difference of $34,854,000 should be removed from rate base in this rate case. The Company should not be earning a return or receive revenue to recover depreciation expense for costs that it did not incur.

E. Corporate Capital Projects

Q. PLEASE DISCUSS THE ADJUSTMENTS THAT YOU PROPOSE TO CAPITAL EXPENDITURES IN THE CORPORATE AND VEHICLE TRANSPORTATION AREAS.

A. In Exhibit A-12, Schedule B5.8, the Company shows forecasted capital expenditures for corporate functions of $138.9 million for 2023, $97.0 million for 2024, and $120.1 million for 2025. Company witness Theresa Uzenski discusses the corporate capital expenditures in her direct testimony. Pages 2 and 3 of Schedule B5.8 provide a list of major projects with the related capital expenditures for 2022 through 2025.

On pages 61 and 62 of her direct testimony, Ms. Uzenski states that certain renovations and updates were necessary at the Company's downtown campus due to employees returning to work for a mandatory minimum 3 days per week, and to build conference and huddle rooms in the lobby of the Cisler building, for a total cost of $14,265,000 between 2023 and 2024.[36] In discovery, the Attorney General asked the Company to explain why employees are required to report to their office location for three days a week versus the

[36] Exhibit A-12, Schedule B5.8 page 2, lines 27-32.

whole week, what efficiencies are gained from the 3-day requirement, and why office space from pre-Covid that accommodated employees for a full week is now not sufficient and needs to be renovated. In response, the Company had no clear answers to the questions, pointing simply to company policy decisions and the need for developing agile work space and reconfiguring office furniture.[37]

Additionally, the AG asked the Company to explain why it was spending capital on new furniture, additional huddle rooms, conference rooms, monitors, work stations, video conferencing and on other items, when those facilities and equipment were previously used by the same employees who worked at the same office location for a full week versus only three days a week now. The responses that employees need equipment both at home and at the office is not persuasive and shows an inclination to increase capital spending to accommodate situations that are not most efficient. It is also perplexing why the Company would need additional video conferencing capabilities four years after the outbreak of Covid-19, which initially increased the use of video conferencing.

The conversion of open space in the lobby of the Cisler building into conference and huddle rooms at a cost of $4.8 million is another example of wasteful spending. For the occasional use that these conference and huddle rooms will have when required by larger

[37] Exhibit AG-16 includes DR AGDE-3.127a-d.

groups, it does not justify the significant cost. Those large groups could gather at other locations that previously accommodated them.[38]

The renovations undertaken at the Company's headquarters building are not a wise use of capital that could be used instead to improve the distribution grid for increased reliability. The expenditures are not prudent and reasonable. Therefore, I recommend that the Commission remove $6,265,000 for 2023 and $8,000,000 for 2024 from the capital expenditures forecasted by the Company.

Q. ARE THERE OTHER CAPITAL EXPENDITURES FOR PROJECTS IN THE CORPORATE AREA THAT NEED TO BE ADJUSTED?

A. Yes. For projects of $3 million or greater, the Attorney General asked the Company to provide a project description, statement of necessity, and a project development timeline with the current phase of the project identified among other pertinent information. In response, the Company identified certain projects with capital expenditures included in 2024 and 2025 where the project is still in the initial concept phase or will not be completed until after the end of the 2025 projected test year.[39]

The information provided by the Company shows 8 projects in the Initial Concept phase with total capital expenditures of $17,600,000. These projects are on lines 22, 24, and 25 of page 2 and lines 8, 9, and 12 of page 3 of Schedule B5.8. The same line number

[38] Id. includes DR ADGDE-3.127e.
[39] Id. includes DR AGDE-3.131a-c with attachments.

correspond to the attachment to DR AGDE-3.131b&c in Exhibit AG-16. These projects are still in the early stage of development and premature to include in rate base. The timing and cost can change significantly before project specifications, design, and work begins on those projects. Customers should not run the risk of paying in rates for costs that the Company may not incur.

Additionally, the Training and Development Center Renovation on line 23 of page 3 of Schedule B5.8 has an in-service date of 2026. This project with forecasted capital expenditures of $7.0 million in 2025 will not be used and useful in 2025 and the capital expenditures should be removed from rate base in this rate case.

Therefore, in total, for the 9 projects, I recommend that the Commission remove $24,600,000 from the Company's forecasted capital expenditures for 2025.

Q. ARE YOU PROPOSING ANY ADJUSTMENTS TO CAPITAL EXPENDITURES FOR VEHICLES AND EQUIPMENT SUPPORTING THE ELECTRICAL OPERATIONS?

A. Yes. On line 1 of Exhibit A-12, Schedule B5.8, the Company shows the capital spending for vehicle fleet supporting the electric operations with forecasted capital expenditures of $32,791,000 for 2023, $38,236,000 for 2024, and $42,600,000 for 2025. In discovery, the Attorney General asked the Company to provide the number of vehicles purchased of each type or class for years 2021 to 2023 and forecasted for 2024 and 2025, with the related dollars.

In response, the Company referenced discovery responses provided to Staff. The information provided to Staff pertains to only 2023 and 2024 and does conform to the request made by the Attorney General.[40] Given this lack of information, a reasonable approach to forecast capital expenditures in this area is to use the average capital spending during the most recent three years and adjust that amount for forecasted inflation in 2024 and 2025.

Based on information provided by the Company, the average amount spent on the transportation fleet was $32,883,000 during the three years 2021 to 2023.[41] Adjusted for inflation, the forecasted capital expenditures are $33,622,000 for 2024 and $34,413,000 for 2025. These amounts are lower than the Company's forecast by $4,564,000 for 2024 and $8,187,000 for 2025. I recommend that the Commission remove those amounts from the Company's forecasted capital expenditures.

F. EV Charging Forward Program

Q. WHAT ADJUSTMENTS TO CAPITAL EXPENDITURES FOR THE EV CHARGING FORWARD PROGRAM DO YOU PROPOSE?

A. In Exhibit A-12, Schedule B5.9, the Company shows a major escalation in capital expenditures in 2024, with $12.5 million of forecasted spending from less than $1.0 million in 2023. Forecasted capital expenditures decline to $5.1 million in 2025. This increase in

[40] AG-17 includes DR AGDE-3.130bii.
[41] Id. includes DR AGDE-3.130a with attachment.

spending presumes an increased interest by businesses for installation of charging infrastructure with very large subsidies paid to those businesses to install chargers and batteries. As stated above in my testimony under the Utility Make Ready capital expenditures, the general interest in electric vehicles is currently waning and throwing more money at the program than demand warrants at this time is not a prudent move.

Therefore, consistent with my recommendations in the Utility Make Ready testimony, I propose that the forecasted capital expenditures in Schedule B5.9 be reduced by 45% for 2024 and 2025.[42] This means a reduction in capital expenditures of $6,979,000 for 2024 and $2,295,000 for 2025. The lower amounts included in rate base will protect customers from the Company's potential underspending on the program. However, if the Company were to exceed those amounts, it can request recovery for the additional amount in the next rate case.

G. Capital Expenditures Adjustments - Summary

Q. WHAT IS THE TOTAL AMOUNT OF ADJUSTMENTS THAT YOU RECOMMEND TO THE COMPANY'S CAPITAL EXPENDITURES AND RATE BASE?

A. The chart below summarizes my proposed reductions in capital expenditures in those areas where the level of capital expenditures presented by the Company is excessive,

[42] Make Ready reductions of $13.9 million from Company's forecasted net UMR of $30.68 million for 2024 and 2025 = 45%.

unnecessary, or unsupported. It also includes capital cost disallowances proposed by other witnesses presenting testimony on behalf of the Attorney General.

Summary of AG Disallowed Capital Expenditures		
		Amount (millions)
Distribution Operations	$	688
Power Generation		34
Nuclear Operations		175
Customer Service/IT		60
Corproate Facilities		52
EV Program		9
Total	$	1,018

Based on my analysis and the information presented in my testimony above, the Commission should reduce the Company's proposed capital expenditures by $1,018 million and average rate base by $783.9 million, including an adjustment of $25.7 million to working capital. Exhibit AG-18 provides additional details and calculations of these amounts.

V. Working Capital

Q. ON EXHIBIT A-12, SCHEDULE B4, THE COMPANY PROPOSES A WORKING CAPITAL AMOUNT OF $1.295 BILLION FOR THE PROJECTED TEST YEAR. DO YOU AGREE WITH THE COMPANY'S FORECASTED AMOUNT?

A. No. I propose three adjustments, which reduce the level of Working Capital for the project by $25.7 million. The first adjustment is to eliminate the Company's regulatory asset of

$9.9 million related to its Ludington power generating facility shown on line 27 of Exhibit A-12, Schedule B4. The second adjustment pertains to the Company's regulatory asset for the Incentive Compensation Deferral shown in Exhibit A-12, Schedule B4. This item is shown on line 41 of the exhibit as a $3.9 million asset. Instead, as explained below, a $6.1 million average liability (not an asset) should be established in the Working Capital projection. This reduces the average Working Capital balance by $10.0 million.

The third adjustment pertains to the regulatory assets for the deferral of costs for the Time of Day (TOD) implementation program. The adjustment amount reduces Working Capital by $5.8 million, as discussed in more detail below.

Q. PLEASE EXPLAIN THE REMOVAL OF THE $9.9 MILLION REGULATORY ASSET FROM WORKING CAPITAL RELATED TO THE COMPANY'S JOINTLY OWNED LUDINGTON PUMPED STORAGE FACILITY.

A. Based on a Commission order in Case No. U-21310, the Company has been deferring certain costs and the estimated liquidated damages pertaining to defective work by Toshiba at the Ludington power generating facility. The net amount of the costs and liquidated damages deferred by the Company and included in a regulatory asset by the Company is $9,933,000. In response to discovery, the Company provided the components of these costs and liquidated damages and stated that the deferred amount represents the balance as of December 3, 2023.[43] The costs pertaining to the power outages, liquidated damages,

[43] Exhibit AG-19 includes DR AGDE-1.20a and b.

and other costs pertaining to Toshiba work problems at the Ludington plant have been a matter of litigation in several Power Supply Cost Recovery cases. The Attorney General and other parties to the proceedings have taken different positions than the Company on whether DTEE should be responsible to absorb the cost of replacement power from multiple and extended power outages at the plant and how liquidated damages should be apportioned to offset replacement power costs and other costs incurred by the Company.

The unsettled dispute and uncertainty as to how much the Company will eventually be allowed to recover of the net deferred costs makes it imperative that the Company should not earn a return on the deferred amount until the Commission rules on the appropriate amount to be recovered in rates. Therefore, I recommend that the Commission remove the $9,933,000 from Working Capital in this rate case. Once the Commission decides the appropriate amount of deferred costs that the Company should be allowed to recover, if any, the appropriate return can be calculated and included with the deferred amount for the period of time that the recoverable portions of the net costs were outstanding.

Q. PLEASE EXPLAIN THE INCENTIVE COMPENSATION DEFERRAL AND HOW THE COMPANY ARRIVED AT ITS DEFERRED BALANCE OF $3.9 MILLION.

In Case No. U-20836, the Commission approved recovery of only 60% of the Company's proposed incentive compensation related to operating performance measures for the projected test year ending October 2023. In addition, the Commission directed the

Company to establish a two-way cost tracking mechanism for incentive compensation earned in the projected test year based on the actual performance level achieved relative to the performance level in the incentive compensation amounts included in rates. The pertinent section of the Commission's November 18, 2022 Order states:

> For operational metrics, the Commission finds the Attorney General's arguments persuasive that DTE Electric should recover costs for operational metrics achieved at target or better over the past five years. The Commission adopts this approach consistent with its December 9 order in DTE Gas's last general rate case, Case No. U-20940. The Commission adopts the Attorney General's 40% disallowance and permits DTE Electric to recover 60% of its proposed incentive compensation expense for operational metrics. The Commission adopts the Attorney General's proposed disallowance of 40% of $21,225,000 for a total EICP expense of $12,735,000. In addition, the Commission authorizes DTE Gas to implement a two-way tracker mechanism, which will require refunds to customers if the 60% target level is not achieved or will allow the company to recover additional funds if it exceeds the 60% target level, up to a maximum of 100% target level.

From reviewing the calculations in Exhibit A-13, Schedule C5.10.1, it is apparent that the Company did not properly follow the methodology that the Commission approved in Case No. U-20836 in determining the amount of incentive compensation that it actually earned during 2023. In filed exhibits, the Company did not show how it arrived at its actual compensation amount of $5,987,000 for 2023. This amount is slightly higher than the $5,943,000 that I calculated in Exhibit AG-20, as discussed in more detail below.

In addition, the Company included in the regulatory asset an accrual of $9.8 million for 2024 incentive compensation that it has not earned yet, on the assumption that it would achieve 100% of its operating incentive metrics for 2024. This is not only premature but

inconsistent with historical performance. As shown later, the Company only achieved 28% of its operating metrics in 2023 at target level or better.

The Company also included an additional accrual for 2022 of $856,000. Although the Company did not discuss this amount in filed testimony or explain it in the exhibit, it is assumed that it is trying to recover the amount of compensation for 43 days from the date of the order in Case No. U-20836 on November 18, 2022 to December 31, 2022. No calculations were provided in filed exhibits to support this amount. However, this amount should be easily dismissed. The Company achieved actual performance on the operating metrics of only 52% at target level or better in 2022. For the projected test year, in Case No. U-20836, the Company received recovery of incentive compensation for operating metrics at 60%. The 52% achieved in 2022 is less than the 60% included in rates, Therefore, if any adjustment should be made for the 43 days in 2022, it would be to reduce the amount recovered in rates and an additional refund to customers. As shown in my calculations in Exhibit AG-20, I exclude any amount pertaining to 2022, concluding that it was de minimis.

The Company's calculation of the regulatory asset for the incentive compensation deferral is inappropriate and the Commission should reject it.

Q. HAVE YOU DETERMINED WHAT THE APPROPRIATE REGULATORY ASSET/LIABILITY BALANCE AND AMORTIZATION EXPENSE FOR 2023 SHOULD BE FOR THE DEFERRED INCENTIVE COMPENSATION AMOUNT?

A. Yes. In Exhibit AG-20, I applied the percentage of actual performance achieved for the operational performance measures in each of the two incentive plans in 2023 to the amount of incentive payout of $21,225,000 at 100% of target that Company witness Michael Cooper forecasted for operating metrics on page 53 of his direct testimony in Case No. U-20836. The $21,225,000 is the base amount on which the Commission approved the 60% recovery amount of $12,735,000 in base rates and should be the same amount on which to calculate the final incentive compensation amount applying the actual performance measures achieved in 2023.

This calculation results in an actual performance incentive amount of $5,943,000 for 2023. When compared to the $12,735,000 included in rates in Case No. U-20836, the difference is an over-recovery of $6,792,000, which is owed by the Company to its customers. Lines 1 through 7 of Exhibit AG-20 show the calculations. The over-recovery results in a regulatory liability of $6,792,000 as of the beginning of the 2025 projected test year, in contrast with the Company's improperly established regulatory asset of $3,884,000.

I propose that the negative balance of $6,792,000 in the regulatory liability be amortized over a five-year period and the annual amortization expense, which is a credit of $1,358,000 in this case, be reflected in O&M expense and in rates beginning with this rate case. I chose a five-year amortization period because it is sufficiently long to smooth out future changes to the regulatory asset as positive or negative accruals are recorded to the account and to minimize volatility to the amortization expense from rate case to rate case. The Company did not propose an amortization expense in this rate case.

The $6,792,000 in regulatory liability I calculated in comparison to the Company regulatory asset of $3,884,000 results in an adjustment of $9,997,000 to working capital, as shown in Exhibit AG-20. Therefore, I recommend that the Commission remove the $9,967,000 from the Company's forecasted working capital balance amount for the projected test year and include the $1,358,000 of negative amortization as a reduction to the Company's forecasted O&M expenses for the projected test year in this rate case.

Q. ON PAGE 86 OF HER TESTIMONY, MS. UZENSKI RECOMMENDS CERTAIN MODIFICATIONS TO THE INCENTIVE COMPENSATION TRACKER MECHANISM. DO YOU AGREE?

A. No. On page 86 of her direct testimony, Ms. Uzenski proposes three modifications. The first modification pertains to setting a new base amount of approved compensation to use for future deferrals. This proposal is appropriate and should be adopted if the Commission decides to continue the mechanism. The second proposal is to also include incentive compensation related to financial measures. This proposal should be rejected. The Commission has repeatedly made it clear that inclusion in rates of incentive compensation related to financial measures is inappropriate and no convincing evidence has been provided in this rate case that the Commission should change its prior decisions.

The third proposal is to include compensation payout above 100% of target. This proposal also should be rejected. As I have stated in my testimony below in the Incentive Compensation section, several of the operating performance measures have a very low

threshold to achieve payout under the plan and it is relatively easy for the Company to exceed the 100% target level without achieving superior performance. The deferral mechanism should not bypass what the Commission has previously accepted as reasonable recovery of incentive compensation capped at 100% of target.

In summary, the Commission should reject the second and third proposed modifications to the mechanism.

Q. PLEASE DISCUSS YOUR ADJUSTMENT TO THE TOD IMPLEMENTATION PROGRAM.

A. On line 27 of Exhibit A-12, Schedule B4, the Company proposed a working capital amount of $5,784,000 for the TOD program. This program was implemented beginning in 2022 to allow the Company to inform and prepare customers for significant changes to customer rate tariffs that would be implemented in 2023. The Company received approval to defer the applicable costs for future review and recovery if deemed prudent and reasonable. In this rate case, the Company filed Exhibit A-13, Schedule C5.9.2, showing that it had incurred net costs of $1,979,000 in 2022 and forecasted additional costs of $6,486,000 for 2023. Included in the 2023 forecasted amount were customer service costs of $5,152,000 for the addition of customer service representatives to handle anticipated additional telephone calls and other related inquiries due to the TOD rate tariff changes.

In neither filed testimony nor in its exhibits, did the Company provide any evidence that the costs incurred in 2022 and forecasted for 2023 were reasonable and prudent. In

discovery, the Attorney General asked the Company to provide the specific costs it incurred for items of $100,000 or greater in order to perform a reasonableness and prudency review. In response, the Company provided summary statements about the major categories of costs it incurred for 2022 and forecasted for 2023, with no itemized list of actual costs or calculations as to how it arrived at the forecasted costs.[44] The information provided is inadequate to establish the reasonableness and prudency of the amounts included in the regulatory assets and partially amortized to expense in this rate case.

The Company included $6,486,000 of forecasted costs for 2023 in determining the regulatory asset and amortization expense, thus attempting to earn a return and recover forecasted costs that cannot be validated for reasonableness and prudency. By removing the forecasted costs for 2023 from the regulatory asset, the working capital balance for the projected test year is reduced to zero and so is the amortization expense of $1,693,000 calculated in Exhibit A-13, Schedule C5.9.3.

Therefore, I recommend that the Commission remove the $5,784,000 of working capital for the TOD program and the $1,693,000 of amortization expense from the Company's forecasted amounts for the projected test year.

[44] Exhibit AG-22 includes DR AGDE-4.156a with attachment.

Q. PLEASE SUMMARIZE THE TOTAL AMOUNT OF ADJUSTMENTS YOU PROPOSE FOR THE PROJECTED TEST YEAR.

A. The three adjustments discussed above total to $25,684,000. I recommend that the Commission reduce the Company's forecasted Working Capital amount for the projected test year by this amount.

Q. IS THERE ANOTHER REGULATORY ASSET FOR DEFERRED TREE TRIMMING COSTS THAT THE COMPANY DID NOT INCLUDE IN WORKING CAPITAL BUT CALCULATED A RETURN SEPARATELY ON THE DEFERRED BALANCE FOR INCLUSION IN THE REVENUE REQUIREMENT?

A. Yes. In Exhibit A-11, Schedule A1.1, the Company calculated a return of $18,786,000 on an average balance of $204,108,000 of deferred costs for the Tree Trimming Surge program.

Q. DO YOU AGREE WITH THE DEFERRED BALANCE AMOUNT AND THE CALCULATION OF THE RETURN?

A. No. There are two problems with the amounts included in Exhibit A-11, Schedule A1.1. First, the Company included $87.0 million of additional tree trimming surge costs in 2025 on the presumption that its previously forecasted surge costs are insufficient to complete the surge program and it needs an additional $110 million between 2025 and 2026 to finish the program. The second problem is the Company's use of a rate of return of 9.20% on

the deferred amount, which is the Company's long-term permanent capital pre-tax rate of return in this rate case. The Commission has repeatedly ruled that the appropriate interest rate to apply to the deferred tree trimming costs is the short-term interest rate. In rate case after rate case, the Company does not seem to want to accept that decision and repeatedly proposes the permanent capital rate of return or the overall pre-tax rate of return, instead of the short-term debt rate, in clear violation of the Commission's orders on this matter.

Q. PLEASE DISCUSS FURTHER YOUR OBJECTION TO THE INCLUSION OF THE ADDITIONAL $87.0 MILLION OF TREE TRIMMING COSTS IN THE REGULATORY ASSET.

A. Beginning on page 15 of her direct testimony, Ms. Rachel Steudle presents an assessment of the Tree Trimming Surge program. Her conclusion is that the 7-year surge program will now cost nearly $1.4 billion, or $251.2 million more than forecasted when the Company proposed the program in 2018 in Case No. U-20162. Ms. Steudle blames higher costs to perform regular cycle clearing of trees and vegetation after the initial surge clearing, higher costs paid to contractors to perform tree trimming, additional costs for spot clearing, additional costs for the Detroit Tree Trimming Academy, and of course inflation.

Ms. Steudle reports that $90 million of the money the Company over-earned during the Covid-19 pandemic helped to offset part of the $251.2 million in additional costs, and with

forecasted efficiencies and a new focus on risk-based tree clearing, she believes an additional $110 million in funding should be sufficient to complete the surge.

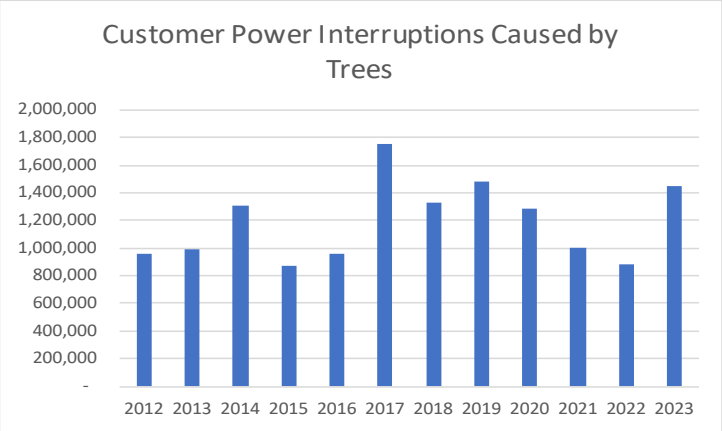
Q. WHAT IS YOUR ASSESSMENT OF THE EFFECTIVENESS OF THE SURGE PROGRAM AND THE REQUEST FOR INCREASED SPENDING ON THE PROGRAM?

A. The $1.4 billion spent on tree trimming from 2019 to 2025 is significantly understated. This amount includes only O&M costs and deferred costs under the surge program. The Company did not include in this amount the additional $496 million spent on tree trimming as part of capital programs when electrical lines and related facilities are replaced or upgraded, which also helps with managing tree growth and avoiding future power outages. Therefore, the full cost of tree trimming over the seven-year period from 2019 to 2025 will be closer to $1.9 billion.

The question then is, what has the Company accomplished with the trimming surge and the $1.9 billion in spending? In discovery, the Attorney General asked the Company to provide the number of power outages caused by trees and vegetation that occurred annually in the last 12 years, from 2012 to 2023, to get a clear perspective on whether the surge and other tree trimming activities have made a significant and clear impact in reducing power outages caused by trees and vegetation. The Company was also asked to provide the number of catastrophic storms and grey days each year to better assess the circumstances faced by the Company during those years. The Company refused to provide data on the

catastrophic and grey days, claiming the information was irrelevant to the topic of tree trimming effectiveness and the conclusions reached on the surge.[45]

However, the Company provided the number of customer interruptions caused by trees and vegetation annually from 2012 to 2023.[46] The following chart shows the number of power outages by year.



Year	Power Outages
2012	959,883
2013	991,109
2014	1,303,242
2015	870,802
2016	957,896
2017	1,748,339
2018	1,326,949
2019	1,477,637
2020	1,287,891
2021	1,003,029
2022	879,774
2023	1,445,908

Although the number of power outages caused by tree seems to be declining from 2019 to 2022, the numbers during this period are the same if not higher than they were during 2012 to 2016. In 2023, the number of power outages caused by trees reverted back to the 2019 level, despite hundreds of millions of dollars spent on tree trimming in the intervening years from 2019 to 2023. If there was a test of the effectiveness of the surge program, it was in 2023, when a severe storm and other large storms provided a clear opportunity to

[45] Exhibit AG-23 includes DR AGDE-4.157b.
[46] Id. includes DR AGDE-4.157a.

gauge whether the increased tree clearing is making a difference. The answer from the data shown above appears to be no.

In her direct testimony, Ms. Steudle states that in 2023 the Company discovered that the costs for on-cycle clearing were running higher than expected. However, data provided by the Company about the cost per mile by year from 2019 to 2023 for the surge program and on-cycle clearing shows a different story. Although in 2023, on-cycle tree trimming costs per mile jump by 41%, from $18,037 in 2022 to $25,496 in 2023, the cost per mile for the surge program increased by 53% in 2022, from $28,507 in 2021 to $43,695 in 2022.[47] Therefore, the Company should have had indications as early as 2022 that tree clearing costs were escalating significantly and could have taken corrective action.

Ms. Steudle attributes part of the increase in tree trimming costs to paying premiums to attract contractors to participate in the Company's tree trimming program. This has certainly been a big contributor to the cost increase and an area that needs special attention and corrective action. During the five years from 2019 to 2023, the Company paid premiums of $80.7 million to up to seven contractors at an average annual premium per contractor of between $1.2 million to $4.2 million. For 2024 and 2025, the Company forecasted payments of an additional $34.5 million to four contractors for an average annual amount of $4.3 million per contractor. In total, the Company expects to pay $115.2 million in contractor premiums over the seven-year period from 2019 to 2025.[48] In

[47] Id. includes DR AGDE-4.159d.
[48] Id. includes DR AGDE-4.163a and b with attachment.

contrast, in Case No. U-20162 the Company initially forecasted that it would incur $45.5 million in contractor premiums. The latest forecast is an alarming 153% increase in additional costs paid to a handful of contractors. The Company needs to take corrective steps to significantly mitigate or eliminate these extra costs for 2024 and 2025.

Q. ARE THERE OTHER COST INCREASES AND DEVELOPMENTS WITH THE SURGE PROGRAM THAT RAISE CONCERNS AND REQUIRE REMEDIAL ACTION?

A. Yes. Included in the $87.0 million of additional surge program costs is a $4.1 million increase in spending for the Detroit Tree Trim Academy. In discovery, the Attorney General asked the Company to provide the number of prospective tree trimmers trained, the number that successfully made it through the program, and the number that are still part of the trimming program. The data provided by the Company shows that of the 221 participants that enrolled and were trained from 2021 to 2023, only 74 are still working in the tree trimming program. This is a retention rate of 33%.[49] Such a low retention rate cannot be considered a success for the millions of dollars spent on the program and the *additional* $4.1 million that the Company wants to allocate to it in 2025. The Company should look at either significantly restructuring the program to at least double the retention rate or, if that goal is not achievable, shut down the academy and reassign those dollars to hiring trained tree trimmers or not spend them at all.

[49] Exhibit AG-24 includes DR AGDE-4.164b.

Another revelation from Ms. Steudle's testimony was the low number of trees actually removed through the surge program versus the number initially forecasted in Case No. U-21062. The Company had targeted to remove between 443,704 and 866,781 trees annually from 2019 to 2023.[50] In reality, the Company removed only between 38% and 48% of the planned numbers. In providing this information in response to discovery, the Company could not identify the specific reasons why so few trees were removed. The Company admits in another discovery response that removing trees minimizes the future workload of on-cycle trimming by decreasing the number of trees that will need to be trimmed in future years.[51] This is again another case of the Company spending more and accomplishing less than forecasted.

Lastly, the Company now wants to change its strategy and use a risk-based approach to tree trimming. Why the Company has not done this previously is a mystery. To implement this new strategy, the Company believes it needs to invest in Lidar technology, along with a risk prioritization model, at a cost of $6.9 million, which the Company included in capital expenditures for 2022 and 2023 in Exhibit A-12, Schedule B5.4, line 24.[52] Asked in discovery if it had performed a cost/benefit analysis to justify the new technology and program, the Company stated that it had not done so and claimed an unsupported 5% reduction in tree trimming costs going forward.[53] In other words, there is no basis or

[50] Id. includes DR AGDE-4.161c and d
[51] Id.
[52] Rachel Steudle direct testimony at page 31.
[53] Exhibit AG-24 incudes DR AGDE-4.166b and c.

indication that this revamped risked-based program will create any new financial benefits for customers to improve on the shortcomings of the current surge program.

Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS?

A. The Company has not made a compelling and convincing case that increasing the amount to be spent on the surge program by $87 million in 2025 and an additional $23 million in 2026 to be charged to O&M expense is advantageous to customers. The evidence points to no significant reductions in power outages caused by trees and vegetation, and instead to significant cost overruns with contractors and other ineffective support programs.

Therefore, I recommend that the Commission reject the Company's proposed increase of $87.0 million in deferred costs in 2025 for the surge program.

Additionally, the Commission should remind the Company once more that the appropriate interest rate to be applied to the deferred costs under the Tree Trimming Surge program is the short-term debt interest rate, which in this rate case is 5.76%, according to page 1 of Exhibit A-14, Schedule D1. The lower interest rate and the removal of the $87.0 million from the average deferred balance, results in a return on the deferred tree trimming costs of $9,900,000, as calculated in Exhibit AG-25. This amount is $8,886,000 lower than the $18,786,000 forecasted by the Company. Therefore, I recommend that the Commission remove the $8,886,000 from the Company's proposed revenue requirement in this rate case.

Furthermore, I recommend that the Commission remove the $3,078,000 in capital expenditures for 2022 and the $3,824,000 for 2023 pertaining to the Tree Trim Risk Prioritization model because the Company did not perform a cost/benefit analysis and did not justify that the model and related expenditures are economically beneficial to customers.

VI. Cost of Capital

A. Capital Structure

Q. **WHAT IS THE CAPITAL STRUCTURE YOU RECOMMEND FOR USE IN THE OVERALL RATE OF RETURN CALCULATION?**

A. I am recommending that the capital structure shown on page 1 of Exhibit AG-26 be used in this case. Lines 1 and 3 show the projected long-term debt and common equity permanent capital of the Company for the test period ending December 2025. The permanent capital balances in this exhibit reflect a 50%/50% capital structure, which are the same percentages reflected in Company Exhibit A-14, Schedule D1. The result is a capital structure with 50% common equity and 50% long term debt, which reflects the capital percentages approved by the Commission in the Company's last general rate case in Case No. U-21297.

Q. DID YOU MAKE ANY ADJUSTMENTS TO THE ITEMS INCLUDED IN THE COMPANY'S PROPOSED CAPITAL STRUCTURE?

A. No.

B. Cost of Capital

Q. WHAT RETURN ON EQUITY AND OVERALL RETURN ON CAPITAL ARE YOU RECOMMENDING IN THIS CASE?

A. I am recommending an overall return on capital of 5.67%, which includes a return on common equity of 9.85%, as shown in Exhibit AG-26.

Q. WHAT COST RATE DID YOU UTILIZE FOR LONG TERM DEBT?

A. I utilized the 4.24% rate determined by Company witness Timothy Lepczyk.

Q. WHAT COST RATE DID YOU UTILIZE FOR SHORT TERM DEBT AND THE OTHER COMPONENTS OF THE CAPITAL STRUCTURE?

A. For Short Term Debt and Deferred Taxes, I utilized the cost rates recommended by Company witness Lepczyk. For JDITC, I used the long-term debt and common equity rates I have proposed applicable to this case.

Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE OVERALL COST OF CAPITAL IN EXHIBIT AG-26?

A. To develop the overall cost of capital on line 11, column (f), I first developed the percentage weighting of each capital component in column (d) by dividing the individual

capital balances in column (b) by the total of all capital components in that column. Next, I multiplied the weightings in column (d) by the cost rates in column (e) to arrive at the values in column (f). The total of the individual values in column (f) is the total cost of capital of 5.67%.

Regarding the pretax weighted cost of capital on line 11, column (h), I multiplied each cost component in column (f) by the conversion factors in column (g). These conversion factors are included to reflect the impact of income and other taxes paid by the Company for calculation of the pretax weighted cost of 7.02% in column (h).

Q. WHAT GENERAL PRINCIPALS HAVE YOU CONSIDERED IN DETERMINING THE COST OF COMMON EQUITY FOR THE COMPANY?

A. A utility company is entitled to a fair return that will allow it to attract capital and be sufficient to assure investors of its financial soundness. In its opinion in Bluefield Water Works and Improvement Company v Public Service Commission of West Virginia (the "Bluefield Case") 262 U.S. 679 (1923), the United States Supreme Court stated that:

> *A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that being made at the same time…on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties…*

The principals of the Bluefield Case were re-affirmed by the U.S. Supreme Court in 1944 in the case FPC v Hope Natural Gas Company, 320 U.S. 591.

Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE COST OF COMMON EQUITY IN EXHIBIT AG-27.

A. Determining the cost of common equity for an enterprise or an industry group is inexact, since investors can only estimate what the future cash flows from any enterprise may be over time. Because of this uncertainty, most financial experts will not rely solely on any one particular method. To determine the cost of common equity, I have utilized three approaches to determine this cost. These are the Discounted Cash Flow (DCF) Method, the Capital Asset Pricing Model (CAPM), and a Utility Risk Premium approach. These methodologies have previously been accepted by the Commission and have generally been accepted by regulatory commissions in other jurisdictions in the United States. Also, I considered the current circumstances in the Capital Markets and any potential changes in the risk profile of DTE Electric and the current state of the Michigan economy. While Exhibit AG-27 shows a calculated cost of common equity of 9.80%, from the three approaches, I recommend an allowed rate of return on equity of 9.85%, which reflects rounding the result up. In connection with these methods for determining the cost of common equity, I have considered the cost of common equity for a proxy group of peer companies.

Q. PLEASE EXPLAIN THE DEVELOPMENT OF YOUR PROXY GROUP OF PEER COMPANIES?

A. As reflected in Exhibit AG-33, to develop my peer group I started with the 38 electric utility companies followed by the Value Line Investment Survey. From this group of companies, I removed six companies due to size considerations, which include Duke, Exelon, Nextera, and Southern Company (much larger companies), as well as two smaller companies with annual revenues at $1.0 billion or less (MGE Energy and Unitil). Next, I removed three companies whose dividends are not growing and two other companies, Fortis (a Canadian company) and Sempra Energy due to its foreign investments. Three other companies that I removed are Hawaiian Electric, Eversourse Energy, and Edison International. These companies face higher risks due to wildfire liabilities and the construction of off-shore wind electric generating facilities. Two other companies I removed are Otter Tail and Nextera Energy. Nextera (parent of Florida Power & Light) was removed due its growing non-utility investments primarily in the power generation business, which is currently more than 40% of the company's total Property Plant & Equipment assets,[54] and its high-risk profile due to severe hurricanes. Otter Tail was removed because its operating income from non-utility operations are now 75% of the total company income.[55] Its plastics and manufacturing businesses have grown significantly

[54] Nextera's 2023 Form 10-K Financial Statements show Property Plant & Equipment of $125.8 Billion for the parent company and $70.6 billion for Florida Power & Light (basically a 55%/45% utility / non-utility split).
[55] See pages 29 to 31 of the 2023 Otter Tail Form 10-K filed with the SEC.

and its business profile no longer meets that of a typical peer utility. Several other companies I disqualified are involved in M&A activity or corporate reorganizations, or are companies facing earnings growth challenges.

Exhibit AG-33 shows the starting group of 38 electric utilities I initially considered with the analysis to arrive at the proposed peer group of companies. The result is the group of ten companies shown in Exhibits AG-28 and AG-29 all of which have growing earnings and dividends, and are comparable to the Company.

Q. HOW DOES YOUR PEER GROUP OF TEN COMPANIES COMPARE TO THE COMPANY'S ELECTRIC PEER GROUP?

A. The Company's electric peer group presented by witness Villadsen consists of a group of 25 companies shown on page 30 of her testimony. This group includes eight of the companies in my peer group plus (a) five companies I removed due to size considerations; (b) four companies: American Electric Power, ALLETE, CenterPoint Energy, and WEC Energy Group, which I excluded due to reorganization / M&A considerations; (c) a number of companies, OGE Energy, Pinnacle West, Evergy, and Entergy, which I removed due to growth challenges or other irregularities; and (d) Edison International, due to uninsured wildfire risk and thus dividend risk. Edison International recorded after-tax charges to earnings of $3.8 billion for wildfire and mudslide damages in 2021.[56] Many of

[56] See Edison International 2021 Form 10-K, page 10.

the companies identified above have extraordinary and unique risks or uncertainties and should not be included in the group of peer companies.

Q. ON PAGE 28 OF HER TESTIMONY, WITNESS VILLADSEN EXPLAINS HER SCREENING CRITERIA FOR DEVELOPMENT OF HER PEER GROUPS. WHAT IS YOUR VIEW OF THESE SCREENING CRITERIA?

A. Dr. Villadsen specifies five criteria. Three of these requirements include (a) investment grade status; (b) a market capitalization of at least $300 million[57]; and (c) the availability of sufficient data for estimation. I will point out that most of the companies followed by Value Line meet these criteria and therefore the use of these criteria by Dr. Villadsen accomplishes little if anything different to select a proper peer group.

Her fourth criterion is that the peer company "must pay dividends with no dividend cuts in three years." Again, most utility companies meet this criterion. Her fifth criterion is that the peer company "cannot have engaged in substantial merger, acquisition or divestiture activity for three years." In this regard, I will point out that two of her peer companies (American Electric Power and CenterPoint Energy) have been looking to sell assets for some time to bolster their balance sheets and reduce risk. These potential transactions can affect the stock price.

[57] Unitil is the smallest electric utility followed by Value Line with a market capitalization of $650 million.

Dr. Villadsen's peer group selection process does not reflect sufficient rigor, often failing to follow even her own criteria. The net result is that certain high-risk companies, as well as poorly matched companies, are included in her peer group to provide an unreliable cost of equity capital.

The Commission should reject the Company's proposed peer group and the cost of equity capital derived from those groups of companies.

Discounted Cash Flow (DCF) Approach

Q. PLEASE DESCRIBE THE DISCOUNTED CASH FLOW ("DCF") APPROACH.

A. The DCF approach is based on the proposition that the price of any security reflects the present value of all future cash flows (dividend flows) from the security discounted at a single discount rate, which in the case of common stocks is the required return of equity. Expressed mathematically, the resulting equation can be reconfigured to solve for the required rate of return. This equation is:

$$R = D/P + g$$

where "R" = the Required Equity Return
"D/P" = the Dividend Yield on the Security
and "g" = the expected growth rate in dividends

Generally, the "D" or dividend is known and the "P" or stock price is also known as the stock trades each day. Also, recent growth in the dividend is known or estimates of growth

furnished by stock analysts can be relied upon with some degree of certainty. With this information, one can solve for "R", which is the required rate of return.

Q. PLEASE EXPLAIN THE RESULTS OF YOUR DCF ANALYSIS.

A. The results of my DCF analysis are summarized in Exhibit AG-28. The stock price information in column (c) on this exhibit reflects the average of the high and low prices for each of these equity securities on each of the 30 trading days from May 1 to June 12, 2023. The annual dividend in column (d) is the average projected dividend level for 2024 and 2025 as calculated by the Value Line Investment Survey. Column (h) shows the average long-term earnings growth rate based on Value Line 2024 projections of earnings per share through the 2027 – 2029 period, and Yahoo Finance analysts' projected growth in earnings per share over the next five years. The resulting calculation of the DCF Method indicates an average required return on common equity of 9.26% for the proxy group. In contrast, Dr. Villadsen proposes a simple DCF ROE result of 11.2% on page 38 of her testimony based on her electric peer group.

Q. **PLEASE EXPLAIN WHY WITNESS VILLADSEN'S 11.2% DCF COST OF EQUITY IS MUCH HIGHER THAN YOUR 9.26% DCF RESULT.**

A. There are two main reasons. First, as noted earlier, Dr. Villadsen included many inappropriate companies in her peer group, which improperly boosted the ROE calculation. Six of these companies have inflated ROE results between 11.0% and 16.7% (Duke Energy, Exelon, NextEra Energy, OGE Energy, Pinnacle West, and the Southern

Company). Second, she again applied her ATWACC adjustment, which the Commission has consistently rejected.

Q. PLEASE EXPLAIN WHAT THE RESULTS OF WITNESS VILLADSEN'S ANALYSIS WOULD BE IF SHE EXCLUDED THE SIX INAPPROPRIATE COMPANIES YOU HAVE IDENTIFIED ABOVE FROM HER ANALYSIS.

A. If we isolate the six companies in the calculation of the DCF ROE, the average ROE result for the six companies is 12.85%. Had Dr. Villadsen excluded those results, her calculated ROE for the remaining companies in her peer group would have been 9.7%. Her calculations for these companies are often based on stale or inflated earnings data and dividend yields. For example, she calculated a 13.4% DCF ROE for Exelon based on stale information. Her growth rate for Exelon shown on Exhibit A-14, Schedule D5.6, Panel A is 9%. It is worth noting that this case was filed in late March 2024 and the information of the peer companies shown in the Company's exhibits is now approximately six months old. Moreover, a 9% growth rate for Exelon (an entirely regulated utility) is excessive and unlikely to be achieved in the long-term.

In contrast, more recent data as of May 10, 2024 shows a dividend yield for Exelon of 4.1%. For earnings growth, Value Line shows annualized EPS growth of 5.5% based on EPS of $2.38 in 2023, growing to $3.10 in 2028.[58] As of early July 2024, Yahoo Finance shows that analysts forecast a 4.2% growth rate for the company for the next five years.

[58] Value Line Investment Survey page 140 dated May 10, 2024.

These facts suggest a DCF ROE rate of approximately 8.3% to 9.6%, which is well below the 13.4% calculated by Dr. Villadsen.

Similarly, the OGE Energy DCF ROE of 16.7% in the Company's calculations is based on stale information. The growth rate for OGE Energy, according to witness Villadsen, is 11.3%. This growth rate is also inflated and unlikely to be achieved in the long-term given that the company is a low-growth, pure combination utility. More recent information shows that OGE Energy's dividend yield is 4.7%. When added to the Value Line EPS growth of 5.7%, the resulting DCF ROE rate is 10.4%, instead of the Company's calculated 16.7%.[59]

Q. WHY ARE THE ATWACC DCF ROE RESULTS CALCULATED BY THE COMPANY HIGHER THAN CONVENTIONAL DCF RESULTS?

A. The key factor causing the escalation in the ATWACC ROE is the use of the stock market value relative to the book value of the common equity for each company in the analysis. Given that stock prices per share are higher than the book value per share, the ATWACC approach inflates the calculated ROEs.

The Commission should recognize the inherent circularity of the ATWACC process. For example, if the ATWACC approach was to become universally embraced by regulatory commissions, the ROEs awarded in regulatory proceedings would increase. These inflated

[59] Value Line Investment Survey page 913 dated June 7, 2024.

ROEs would then result in higher utility earnings, stock prices, and higher market to book ratios for utility common stocks. The subsequent calculated ROEs in new rate cases under the ATWACC method would then produce even higher awarded ROEs because the ATWACC would use the higher stock market equity capitalization.

It is likely because of this cost inflating circularity and the complexity of the methodology that the ATWACC approach has not been embraced by state regulatory commissions. In fact, asked to provide evidence that the methodology has been accepted by state regulatory commissions, the Company could not identify any situations.[60] These instances are (1) property taxation disputes in Colorado; (2) Florida's regulation of small water companies; (3) a valuation dispute before the FERC; (4) revenue adequacy hearings for railroads; and (5) a revenue adequacy hearing involving Alabama Power related to its special rate RSE. Nowhere in her testimony does witness Villadsen mention any state regulatory commissions in the United States endorsing ATWACC in a general rate case proceeding. Therefore, the Commission should disregard the ATWACC approach to calculate the DCF cost of common equity.

Q. HAS THE COMMISSION EXPRESSED ITS VIEWS REGARDING THE ATWACC APPROACH AND FINANCIAL LEVERAGE ADJUSTMENTS?

[60] DR AGDE-1.9a.

A. Yes, in one of the Company's recent rate cases both the ALJ and the Commission stated that such adjustments were not appropriate. The Commission's order in that case states the following.

> Further, the Commission adopts the ALJ's findings and conclusions regarding DTE Electric's financial leverage adjustments. The Commission again emphasizes that adjusting for financial risk or applying financial leverage adjustments is not appropriate. While there was some dispute with respect to the terminology used to describe the company's adjustment, the Commission agrees with the ALJ's determination that the parties were referring to the same adjustment. *See*, PFD p. 446, n. 1289. As quoted by the ALJ at page 447 of the PFD, in the December 9 order, the Commission held that it "has consistently taken a traditional approach to establishing ROE, consistent with the principles of Hope Natural Gas and Bluefield Waterworks" and that the application of ATWACC or other financial leverage adjustments "may excessively inflate ROEs, stock prices, and market-to-book ratios for utilities…. Therefore, the ALJ's rejection of the Company's financial leverage adjustment is well supported by the record and Commission precedent….[61]

The same approach has been proposed by the Company in this rate case and the Commission should reach the same conclusion.

Q. PLEASE ASSESS THE RESULTS OF THE DCF ANALYSIS YOU PERFORMED.

A. The DCF analysis relies upon financial market information for the dividend yield portion of the equation. It also relies upon judgments of growth prospects by security analysts, which influence the beliefs of investors. I will point out that the forecasted growth rates in my proxy group include some high growth rates, which in some cases are between 6% and 7%. While these earnings growth rates may materialize in the short term, they may not be sustainable long-term growth rates for electric utilities given that customer and

[61] Case No. U-20836, MPSC Order dated November 18, 2022 at page 241.

revenue growth continue to be barely in low single digits. As such, the results of the DCF analysis in some cases reflect a return on equity rate that is somewhat higher than what investors currently expect in the long term. Nevertheless, I place a fairly high degree of reliability on the DCF results when considered in conjunction with the results of other approaches to determining the cost of common equity.

Capital Asset Pricing Model Approach

Q. PLEASE EXPLAIN THE CAPITAL ASSET PRICING MODEL APPROACH TO DETERMINING THE COST OF COMMON EQUITY CAPITAL.

A. The Capital Asset Pricing Model ("CAPM") is based on the proposition that the expected return on a common equity security is a function of risk as measured by the "Beta" of that security. In equation form, CAPM is as follows:

$k_e = R_f + (B \times R_p)$ *where*

k_e = *The market cost of common equity for a specific security*

R_f = *the "risk free" rate of return*

R_p = *the overall return of the market less the risk free rate (over several years)*

B = *the systematic risk of a particular common equity security vs. the market*

Q. PLEASE EXPLAIN THE BETA OR "*B*" COMPONENT OF THE EQUATION.

A. This measure of risk reflects the extent to which the price of a particular security varies in relationship to the movement of the overall market. Some securities vary less in price over

time than the overall market. In these cases, the Beta will be less than 1.00. Securities that vary over time more than the overall market will have a Beta that is greater than 1.00.

Q. PLEASE EXPLAIN EXHIBIT AG-29 AND THE RESULTS OF THE CAPM APPROACH.

A. Exhibit AG-29 shows the results of the CAPM method based upon (1) a projected 4.05% risk free rate as explained below; (2) Beta information available from Value Line; and (3) the historical Market Risk Premium (R_p) of 7.17% based on the 2023 Ibbotson Classic Yearbook.

Regarding the use of a risk-free rate for CAPM purposes, I used a 4.05% rate determined from information provided by the Company showing projected 10-year U.S. Treasury rates.[62] First, I used the January 1, 2024 Blue Chip average projected rate for 2025 of 3.7%. Second, I used the May 10, 2024 Blue Chip average projection for 2025 of 4.0%. To these forecasted rates, I added 20 basis points to take into consideration the actual average spread between the 10-year and the 30-year U.S. Treasury rate during the first half of July 2024, which produces 30-year forecasted U.S. Treasury rates of 3.9% and 4.2%. Recognizing the uncertainty in the capital markets as to when the Federal Reserve bank will reduce interest rates, I believe that taking an average of the two forecasted rates is appropriate. The result is a 4.05% risk-free rate for the 30-year U.S. Treasury bond.

[62] DR AGDE-1.4 included the Blue Chip reports provided by the Company.

As shown in Exhibit AG-29, I added the beta adjusted peer group risk premium of 6.52% to the 4.05% risk-free rate, to arrive at the 10.57% ROE rate under the CAPM approach.

Q. PLEASE COMMENT ON WITNESS VILLADSEN'S CALCULATIONS OF CAPM COMMON EQUITY COST RATES FOR HER ELECTRIC PEER GROUP RANGING FROM 10.9% TO 11.7%.

A. In Figure 10 on page 35 of her direct testimony, witness Villadsen presents four different CAPM estimates for her electric sample group. In addition, she presents an equal number of estimates under her ECAPM approach, but the ECAPM results are essentially the same as the CAPM estimates. The Commission should not rely upon any of these CAPM and ECAPM results, because all of the estimates have been determined utilizing the Hamada approach with leveraged betas. The Hamada approach is similar to the ATWACC approach, and both of these methodologies lead to faulty and inflated results. In my testimony above, I explained the Commission's previous stated position on these market-leveraged adjustments.

Witness Villadsen's CAPM estimates on page 35 of her testimony show rates calculated under two different scenarios, with market risk premium (MRP) rates based on the traditional historical Ibbotson series and alternatively based on Bloomberg's MRP estimates. On page 34 of her testimony, she states that these two scenarios provide "a range of cost of equity estimates" which are 10.9% to 11.7%.

However, her CAPM results before applying the Hamada adjustment are 10.2% to 11.0%, as shown on her Exhibit A-14, Schedule D5.11 (Panel A and Panel B) at the bottom of the first column in each case. As can be seen in the table below, the midpoint of this range at 10.6% is very similar to my own result of 10.57% without the Hamada adjustments.

Villadsen Figure 10 CAPM ROEs Adjusted	**Scen. 1**	**Scen. 2**
Figure 10 CAPM ROEs (Line 1)	11.70%	10.90%
Less Hamada Impact from below	-0.70%	-0.70%
Adjusted CAPM ROEs	**11.00%**	**10.20%**
Midpoint of Scenario 1 and Scenario 2	**10.60%**	

Additionally witness Villadsen recommends that a further downward adjustment to the CAPM results should be considered by the Commission under the ECAPM method. She proposes reducing one of her outcomes by 0.1% to reflect the ECAPM. This adjustment is subjective, unconventional, and not supported. As I have stated in other cases brought before the Commission by the Company, I remain opposed to the ECAPM. However, since it has no practical importance in this case, I am not dedicating additional testimony to addressing the shortcomings of ECAPM.

Q. PLEASE ASSESS THE CAPM APPROACH.

A. I believe that CAPM has value in assessing the relative risk of different stocks or portfolios of stocks. As such, it can be useful. However, the key issue with CAPM is that is assumes

that the entire risk of a stock can be measured by the "Beta" component and as such the only risk an investor faces is created by fluctuations in the overall market. In actuality, investors take into consideration company-specific factors in assessing the risk of each particular security. As such, I give the CAPM approach less weight than the DCF approach in determining the cost of common equity.

Utility Risk Premium Approach

Q. PLEASE EXPLAIN THE UTILITY RISK PREMIUM APPROACH OF ESTIMATING THE COST OF COMMON EQUITY.

A. In general, one can estimate the cost of common equity by estimating three components and adding them together. The three components are (1) the risk-free rate of return on 30-year U.S. Treasury Bonds; (2) the historical differential between yields of the rated utility bonds of the Company and the 30-year U.S. Treasury Bonds (risk-free rate); and (3) the average return differential of utility common stocks over utility bonds.

Q. PLEASE EXPLAIN YOUR UTILITY RISK PREMIUM ANALYSIS RESULTS.

A. Exhibit AG-30 shows the three components required to estimate the cost of common equity under this approach. The results for this approach reflect a return on common equity of 10.1%. To arrive at this result, I used the 4.38% historical spread of electric utility common stock returns relative to utility bonds. I also used a 1.67% average spread for "A" rated and "BBB" rated utility bonds over the U.S. Government bonds (the risk-free

rate). For the risk-free rate, I used the projected 30-year Treasury rate of 4.05% discussed under the CAPM section of my testimony.

Q. **DOES THE COMPANY PROVIDE A UTILITY RISK PREMIUM ANALYSIS?**

A. No, not in the traditional sense of measuring achieved returns on utility stocks relative to an interest rate benchmark such as utility bonds.

Q. PLEASE COMMENT ON WITNESS VILLADSEN'S TESTIMONY ON PAGES 38 THROUGH 40, STARTING UNDER THE HEADING "RISK PREMIUM APPROACH AND COST OF EQUITY ESTIMATE" ON PAGE 38?

A. In her testimony, Dr. Villadsen states that she compared authorized ROEs from electric utility rate case decisions to 20-year U.S. Treasury bonds from 1990 to 2023. She ran a regression model with this data and observed that ROE rates have fallen more slowly than treasury bonds. Based on this analysis she concludes that an ROE of 10.5% for electric utilities would be appropriate based on the 20-year forecasted U.S. Treasury rate of approximately 4.30%.

There are several flaws with this analysis. Chief among them is the premise that treasury bond yields are the primary driver in ROE decisions by regulators. It is also not connected to stock market performance or investor expectations of returns on investment. This analysis has no validity as a tool to determine the ROE to be established in rate proceedings. Regulators approach the serious business of establishing a ROE based on

many factors and often exercise "gradualism" in the process as well. The Commission should give this analysis no weight in this case.

Q. **HOW HAS THE ECONOMIC AND INTEREST RATE ENVIRONMENT CHANGED IN RECENT YEARS FOR THE COMPANY?**

A. The U.S. economy and the Michigan economy have generally recovered from the 2020 recession caused by the Covid-19 pandemic, thanks in part to the accommodative stance of the U.S. Federal Reserve Bank during 2020 and 2021 by reducing interest rates. More recently, in late 2022 and early 2023 inflation has been a concern. To combat this threat, the Federal Reserve Bank increased short term interest rates. Inflation in late 2023 and so far in 2024 has fallen, with the CPI reflecting monthly rates of 0.3%, zero, and -0.1% for the three months of April, May, and June 2024.[63] Sentiment in the June/July 2024 period is fairly universal that the Federal Reserve will soon begin to cut short-term interest rates and this should result in falling long-term interest rates as reflected in the Blue Chip reports mentioned earlier in my testimony. Lower interest rates will benefit the Company with lower financing costs and lower the cost of equity capital.

In my calculations on the cost of equity in this rate case for both the CAPM and Utility Risk Premium methods, I reflected those expectations with a projected 4.05% risk free rate for the U.S. 30-year Treasury Bond for the projected test year.

[63] U.S. Bureau of Labor Statistics press release of July 11, 2024 and Table A included therein.

The Company's access to the capital markets has remained strong, as witnessed by DTE Electric's issuance in February 2024 of $500 million of new 10-year long-term debt at a rate of 5.2% and $500 million of 2-year debt at a 4.85%.[64] The Company's senior secured debt ratings are A/Aa3 and its commercial paper program is rated P-1 (highest) by Moody's Investor Service. Also, the Company's parent, DTE Energy, accessed the capital markets in February 2024, issuing approximately $1.2 billion of 5-year long-term debt at a rate of 5.1% and again in April 2024 issuing $850 million of 10-year long-term debt at a rate of 5.85%.[65]

Q. PLEASE DISCUSS WHAT RETURN ON EQUITY RATES OTHER REGULATORY COMMISSIONS GRANTED TO ELECTRIC UTILITIES IN 2022 AND 2023.

A. In Exhibit AG-31, I have segmented the ROE decisions into two groups. Pages 1 and 2 of Exhibit AG-31 show the most recent ROE decisions with ROE rates granted below 9.9%. This by far represents the largest group of ROE decisions with 23 of 32 decisions during 2022 and 38 out of 48 decisions in 2023. For the grouping of companies with ROE rates below 9.9%, these rates range from a low of 7.85% for Ameren-Illinois to a high of 9.80% for Wisconsin Power in Light. The average ROE for this group was 9.29% in 2022 and 9.48% in 2023.

[64] See DTE Energy 1st quarter Form 10-Q filed with the SEC.
[65] See Forms FWP dated February 12, 2024 and April 29, 2024 filed with the SEC

Page 3 of the exhibit is a summary of all ROE rates granted, including those at 9.9% and above, which in 2022 and 2023 was limited to eleven ROE decisions in California and eight other ROE decisions in other jurisdictions, including three in Michigan. Inclusive of these additional utilities, the overall average ROE rate was 9.54% in 2022 and 9.66% in 2023.

The information provided in this exhibit is based on ROE rates granted by state regulatory commissions in general rate cases for electric utilities during 2022 and 2023 and published by Regulatory Research Associates, a respected and independent regulatory research firm.

From this information, it is apparent that the 9.9% ROE granted to DTEE in 2023 and similarly granted to other utilities in Michigan are outlier ROE rates considerably higher than the equity returns granted by state regulatory agencies for most other electric utilities. Other outlier ROE rates of 9.9% and higher granted to electric utilities are mainly in California (eleven decisions), Ohio, North Carolina, Georgia, Alaska, and four decisions issued by the Michigan Commission.

Exhibit AG-31 also includes information regarding debt financing subsequent to the issuance of the rate orders. It is clear from this information that the debt capital markets have remained strong and continue to provide debt capital at competitive interest rates to utilities with authorized ROEs well below the average ROE rate of 9.48% in 2023.

Q. SHOULD THE COMMISSION BE CONCERNED THAT ESTABLISHING AN AUTHORIZED ROE OF 9.85% IN THIS CASE WILL LEAD TO IMPAIRMENT OF THE COMPANY'S ABILITY TO ACCESS THE CAPITAL MARKETS?

A. No. In recent general rate case proceedings, the Commission seems to have been persuaded by the applicants' arguments that they should receive an ROE rate of 10% or higher to ensure the financial soundness of the business and to maintain a strong ability to attract capital in addition to being compensated for risk. Pages 1 and 2 of Exhibit AG-31 show several utilities that have accessed the capital markets at competitive interest rates since receiving an ROE substantially below 9.9% as well as below the average rate of 9.50%.

Similarly, there is no evidence equity investors have abandoned utilities that have been granted ROEs below 10%. On the contrary, stock investors continue to migrate to utility stocks recognizing that authorized ROEs are still above the true cost of equity. Exhibit AG-39 shows the market to book ratios for each of the peer group companies, and many of these companies have received rate orders during the past two years reflecting ROEs ranging from 7.85% (Ameren-Illinois in 2022) to 9.9% (CMS Energy in 2023). Yet this group of companies has an average ratio of Market price to Book common equity value of more than 1.6 times book value, indicating that utilities are earning returns above the investor expected cost of equity on book value.

This information is provided to dispel the myth that the Company must receive an ROE rate above the industry average or it will face dire consequences in the financial markets.

The fact that the Company needs to raise capital because of a large capital investment program to upgrade its infrastructure and for other purposes is not unique to DTE Electric. Other electric and gas utilities face the same issues and are able to raise capital with ROEs at or below my proposed ROE rate of 9.85%. Therefore, this issue is another "red herring."

Q. HAVE YOU DETERMINED THE RETURN ON EQUITY RATES GRANTED TO UTILITIES IN SURROUNDING STATES OUTSIDE OF MICHIGAN DURING 2023?

A. Yes. Exhibit AG-32 shows nine decisions rendered in 2023 in surrounding states which range from a low of 8.72% to a high of 9.80%, and which average to 9.49%. Even in Wisconsin, where rates were recently as high as 10%, ROE decisions in 2023 declined to 9.7% and 9.8%.

Q. WOULD A REDUCTION IN THE COMPANY'S ROE TO 9.85% HAVE AN IMPACT ON THE COMPANY'S DEBT RATINGS?

A. It is unlikely that a downgrade would occur simply due to a slightly lower ROE rate. Moody's rates the Company's debt as "Aa" and views the Michigan regulatory environment as constructive. A review of the most recent Moody's report on DTEE shows that the Company achieved a 20.2% CFO pre-WC to Debt ratio during the twelve months

ended March 2023. This is a key ratio that Moody's uses to evaluate the Company's credit worthiness. It is Moody's position that ratio results under 21% for a sustained time could lead to a downgrade of the Company's debt. I will point out, however, that DTEE's capital structure was more leveraged during this timeframe than the 50%/50% debt and common equity used to set rates in the Company's last two rate cases.

In Exhibit AG-35, I calculated a pro-forma CFO pre-WC to Debt ratio based on the Company receiving and earning an ROE rate of 9.85%. The calculations in the exhibit start with the actual ratio for the twelve months ended March 2023 and the adjustments needed to reflect a 50% common equity ratio and a 9.85% ROE rate. After making these adjustments the CFO pre-WC to Debt ratio increases from 20.2% to 22.3%, which is comfortably above the 21% long-term downgrade threshold set by Moody's.

Q. ON PAGE 52 OF ITS SEPTEMBER 13, 2018 ORDER IN CASE U-18999, THE COMMISSION POINTED TO INCREASED VOLATILITY IN THE CAPITAL MARKETS AS A REASON TO AUTHORIZE A 10% ROE RATE. SHOULD STOCK MARKET VOLATILITY OR THE VIX INDEX BE A CONCERN IN ESTABLISHING A FAIR ROE FOR THE COMPANY?

A. No. Historically, the stock market has been very volatile. Currently, this is measured by the VIX, which portrays volatility over the next 30 days. Company witness Villadsen addresses the VIX on page 22 of her testimony, suggesting that the VIX is somehow

relevant. She reports the VIX was "…higher at about 22 at the end of October 2023…."[66] In discovery, the AG asked the Company to provide any long-term projections of the VIX for the projected test year. In response, witness Villadsen stated that she did not have a long-term projection of the VIX.[67]

The key point that needs to be made is that the VIX is telling us something about risk in the market over the next 30 days and not risk several months into the future. In setting ROE rates for utilities, the Commission's focus is the long-term financial health of the utility not the short-term gyrations of the stock market.

Furthermore, in Exhibit AG-36, I included a Value Line Funds article written by Mitchell Appel, President of Value Line Funds. Mr. Appel states that volatility is not risk. Mr. Appel goes on to say later in this article that "…volatility is only risk if you act during down times, that is, only if you sell a stock."

I will submit that those who invest money in portfolios over longer periods of time and particularly in utility stocks have an aversion to market volatility and the VIX. In fact, utility stocks are a safe haven for investors during times of uncertainty and volatility because they are not as susceptible to as much volatility as the general stock market. This is reflected in the average beta of 0.91 of the utility peer group used in the CAPM ROE rate calculation discussed earlier. This is in contrast with the general stock market value

[66] Villadsen testimony at page 22, lines 8 and 9.
[67] DR AGDE-1.7.

of 1.00. Therefore, the Commission should not give any weight to arguments that the Company's ROE rate should reflect investors' concerns with stock market volatility.

Q. PLEASE EXPLAIN YOUR CONCLUSION CONCERNING THE APPROPRIATE RETURN ON EQUITY RATE THAT THE COMMISSION SHOULD USE IN THIS CASE.

A. In Exhibit AG-27, I summarized the cost of equity rates from the three methods I used. The range of returns for the industry peer group is from 9.26% at the low end, using the DCF approach, to 10.57% at the high end using the CAPM approach.

As explained earlier in my testimony, I give more weight to the DCF method as a more reliable approach to estimating the cost of equity for utilities, which in my analysis is 9.18%. In this regard, on line 4 of Exhibit AG-27, I calculated a weighted return on equity of the three methodologies using a 50% weight for DCF and 25% for each of the other two methods. The result is a weighted return on equity of 9.80%. To this base cost of equity capital I added an additional premium adjustment of 5 basis points, to arrive at a recommended ROE rate of 9.85% for this rate case. The additional 5 basis points provide an added cushion to the ROE rate, should interest rates fall slower than anticipated.

Michigan utilities currently enjoy some of the highest ROE rates among utilities in the country. As shown in Exhibit AG-31, ROE rates granted to Michigan utilities in 2022 and 2023 are at the highest end of the range among most utilities in the country and well above the national average rate and the Midwest average of 9.50%. In prior rate cases, the

Commission has expressed a desire to gradually reduce those ROEs. This rate case provides an opportunity for the Commission to do so by setting the Company's ROE rate at 9.85%.

Q. IF THE COMMISSION APPROVES THE SAME 9.90% ROE RATE IN THIS CASE AS IT DID IN THE COMPANY'S PRIOR RATE CASE, WHAT IS THE COST TO CUSTOMERS COMPARED TO AN ROE OF 9.85%?

A. If the Commission were to grant a 9.90% ROE in this case versus a 9.85% ROE, the additional cost to customers is approximately $6.4 million annually. There is absolutely no need to burden customers with this additional cost, when historically the Company has been earning well above its authorized ROE.

I recommend that the Commission take note of the evidence and arguments I have presented in my testimony and grant the Company an ROE of no more than 9.85%.

VII. O&M Expense Adjustments

Q. WHAT AMOUNT OF O&M EXPENSE DID THE COMPANY INCUR DURING 2022 AND WHAT IS THE AMOUNT OF EXPENSE REQUESTED FOR THE 2025 PROJECTED TEST YEAR?

A. As shown in Exhibit A-13, Schedule C5, the Adjusted Historical Test Period O&M expense for 2022 is $1.224 billion. The Company forecasted that O&M expenses will increase to $1.267 billion during the test year ending December 2025. While the

Company's projected expense level represents a 3.5% increase, or $43 million, over the historical level, there are many offsetting changes which should be noted. Cost reductions of approximately $108 million are reflected in the projected test year, primarily from the closing of three power plants ($31 million), lower nuclear expenses ($47 million), the removal and deferral of pension expense, and lower OPEB expenses ($30 million). Offsetting these expense reductions is $87 million of forecasted inflation cost increases for wages and other expenses.

Q. IN YOUR ANALYSIS, HAVE YOU IDENTIFIED AREAS WHERE EXPENSES SHOULD BE REDUCED

Yes. As a result of my analysis, I have identified $123.5 million of expense reductions, which I will discuss in more detail below. Exhibit AG-37 provides a summary of my proposed adjustments.

A. Inflation Adjustments - O&M Expense

Q. HAVE YOU MADE ANY CHANGES TO THE INFLATION AND MERIT INCREASE ADJUSTMENTS TO O&M EXPENSES PROPOSED BY THE COMPANY IN THIS RATE CASE?

A. Yes. The Company used a form of blended inflation based partially upon projected CPI rates with a 16% weighting, and a 3% wage inflation rate with an 84% weighting. The development of these blended inflation rates is shown on Exhibit A-13, Schedule C5.15

and the blended rates are 3.20% for 2023, 2.90% for 2024, and 2.90% for 2025. The use of a "blended rate" inclusive of wage increases has been rejected in recent general rate cases and the Commission should do so again in this rate case. Instead, the Commission has previously adopted the use of the CPI-Urban area inflation rates to forecast future cost increases when warranted. As discussed under the Capital Expenditures section of my testimony above, I used a forecasted CPI rate of 2.4% for 2024 and 2.2% for 2025.

The Company used the 2022 O&M expense base to develop its inflation adjustments. However, in 2023 the Company took steps to significantly reduce O&M expenses, which makes the 2022 expense amount stale and no longer reflective of the Company's cost structure for the projected test year. In calculating the appropriate amount of inflationary cost increases for 2024 and 2025, I used the actual normalized 2023 O&M expense amounts provided by the Company in response to discovery.

Q. PLEASE EXPLAIN YOUR EXHIBIT AG-38 SHOWING THE RECALCULATION OF INFLATION AT CPI RATES APPLIED TO 2023 COSTS.

A. In Exhibit AG-38, I begin in column (b) with the actual normalized 2023 expense provided by the Company. In columns (c) and (d) I applied the two-year inflation rate of 4.65% to the actual 2023 expenses to determine the proper amount of inflationary cost shown in column (d).[68] Column (e) is the sum of the inflation adjustments calculated by the

[68] The 4.65% two-year inflation rate is the result of combining CPI rates of 2.4% for 2024 and 2.2% for 2025.

Company for 2024 and 2025 and shown in Exhibit A-13, Schedule C5. The difference between the amount of inflation adjustment I calculated versus the Company's amount is shown in column (f) and totals to $14.6 million. This amount reflects the difference between the CPI rates and the blended inflation factors used by the Company and also the lower O&M expense base in 2023 versus 2022.

Accordingly, I recommend that the Commission reduce the Company's O&M expense by $14.6 million for the updated inflation adjustments for 2024 and 2025.

B. Steam Generation Expenses

Q. IN EXHIBIT A-12, SCHEDULE C5.1, THE COMPANY FORECASTED O&M EXPENSES FOR STEAM POWER GENERATION OF $213.4 MILLION FOR THE PROJECTED TEST YEAR. DO YOU AGREE WITH THE COMPANY'S FORECASTED AMOUNT?

A. No. Based on the more recent 2023 expense information provided by the Company in discovery, the Company's forecasted O&M expense in the Steam Power Generation area for the projected test year is excessive. The actual normalized expense for 2023 is $183.0 million, or approximately $30 million lower than in 2022, which the Company used as a basis to forecast the projected test year expense.

In Exhibit AG-39, I calculated the projected test year O&M expense using the 2023 normalized expense of $183 million. After adjusting for two years of inflation for 2024

and 2025 at the CPI rates, I arrived at a 2025 expense amount of $191.5 million. This updated forecast is $21.5 million lower than the Company's forecasted amount of $213.4 million.

My updated O&M expense reflects a more accurate forecast of the projected test year expense for Steam Generation due to recent cost reductions and power plant retirements undertaken by the Company. Therefore, I recommend that the Commission reduce the Company's forecasted O&M expense by $21.9 million.

C. Voluntary Separation Program

Q HAS THE COMPANY INITIATED ADDITIONAL COST REDUCTIONS IN 2024 THAT WILL FURTHER REDUCE O&M EXPENSE IN THE PROJECTED TEST YEAR?

A. Yes. In response to discovery, the Company stated that in January 2024, it offered a Voluntary Separation Incentive Plan to 1,025 DTE Electric employees and 1,622 DTE Corporate Services employees. Of those eligible employees, 140 DTE Electric employees and 249 Corporate Services employees accepted the separation plan, with employee reductions occurring during the first half of 2024. In the discovery responses, the Company also stated that up to $20.3 million of labor and benefit cost savings could be achieved in 2025.[69]

[69] Exhibit AG-45 includes DR AGDE-1.23c.

The preliminary cost savings for 2025 estimated by the Company are real and significant and should be included in the projected test year as a reduction of future O&M expenses. However, conservatively, I included only half, or $10.1 million, of the currently estimated cost savings of $20.3 million as a reduction to the O&M expense for the projected test year. The remaining half of the cost savings plus the cost savings that the Company will retain during 2024 will go a long way to offset the costs that the Company will incur in 2024 to achieve those savings.

Therefore, I recommend that the Commission accept this additional adjustment of $10.1 million to the forecasted O&M expense for the projected test year.

D. Tree Trimming Cost Savings

Q. DID THE COMPANY IDENTIFY CERTAIN COST SAVINGS THAT WILL BE REALIZED IN 2025 AS A RESULT OF THE SURGE PROGRAM AND ACCELERATED TREE TRIMMING?

A. Yes. Ms. Hartwick's Exhibit A-22, Schedule L1, shows cost level reductions related to the Tree Trimming Surge Program. Exhibit AG-40 shows my analysis based on the Company exhibit and a response to discovery of declining costs for reactive tree trimming, storm related tree trimming, and other distribution related costs as a result of more trees being trimmed under the surge program compared to the cost levels in 2022. Based on the information provided, my analysis shows that the Company should achieve O&M cost savings of $17.6 million as a result of the spending on the surge program from 2022 to

2025. The reduction in costs is shown on line 4 of Exhibit AG-40. The $17.6 million matches the information for O&M cost savings provided by the Company in response to DR AGDE-4.167.[70] Subtracting the $8.8 million benefit already included by the Company in Exhibit A-13, Schedule C5.6, results in an additional savings of $8.8 million, which the Company did not include in its O&M expense for the projected test year.

Therefore, I recommend that the Commission remove the $8.8 million in additional cost savings from the Company's forecasted O&M expense.

E. Credit/Debit Card Merchant Fees

Q. ARE YOU PROPOSING ANY CHANGES TO THE COMPANY'S CREDIT/DEBIT CARD PAYMENT PROGRAM OR ADJUSTMENTS TO RELATED O&M EXPENSE?

A. Yes. The Company currently allows residential and commercial/industrial (non-residential) customers to pay their electric bills with a credit or debit card. Until about 2016, the number of customers using debit and credits cards was relatively low. Subsequent to changes made to the Company's SAP system, which allowed more customers to use credit cards, the volume of credit card payments increased dramatically. For DTE Electric, merchant fees reached nearly $11.8 million in 2022 and have ebbed

[70] Exhibit AG-7.

somewhat in the past two years after the Company imposed certain limitations on the use of credit/debit cards by non-residential customers.[71]

Beginning on page 62 of her direct testimony, Ms. Pina Bennett discusses the recent history of debit/credit cards and presents data on merchant fees paid by the Company. Although, in recent years the Company has begun to limit the use of credit/debit cards for non-residential customers, the cost is still significant. For the projected test year, the Company forecasted $8,822,000 in merchant fees pertaining to residential customers and $3,474,000 for non-residential customers, for a total forecasted expense of $12,296,000.

Q. WHAT IS YOUR PROPOSAL?

A. I propose that the Commission disallow recovery of merchant fees for non-residential customers beginning with the costs included in the projected test year in this rate case. This proposal will remove $3,474,000 from forecasted expense for the projected year. Non-residential customers, which consist primarily of small to medium size commercial and industrial businesses, have more options and sophistication than residential customers to pay their gas and electric bills through other less costly means, such as Electronic Funds Transfer (EFT) and Automatic Clearing House (ACH). In response to discovery, the Company reported that an EFT or ACH transaction charge is approximately 10 to 11 cents. In contrast, the merchant fee for the use of a credit/debit card for non-residential customers

[71] Exhibit A-13, Schedule C5.7.1.

is $4.72 per transaction.[72] This large disparity in cost is not reasonable and should be avoided.

In late 2023, Consumers Energy came to the realization that removing the credit/debit card convenience fee previously charged to customers was neither sustainable nor in the best interest of the majority of its customers, due to the large escalation in merchant fees. Beginning in 2024, Consumers Energy reimposed a convenience fee for all customers, both residential and non-residential, who want to use a credit card. This is a step that the Company should evaluate in the coming months and address accordingly. With the large escalation in merchant fees in recent years, more businesses, from restaurants to retail shops, are imposing a convenience fee when customers pay for goods and services with a credit card. Of course, gasoline stations placed a premium on gasoline sales with a credit card long ago.

Therefore, at this time, I recommend that the Commission disallow recovery of the $3.5 million of merchant fees pertaining to non-residential customers so that the Company can take appropriate actions to avoid those costs beginning with the projected test year in this rate case.

[72] Exhibit AG-46 includes DR AGDE-1.28g and d. The $4.72 merchant fee is stated on page 64 of Ms. Bennett's direct testimony on line 2.

F. Uncollectible Accounts Expense

Q. PLEASE SUMMARIZE HOW THE COMPANY ARRIVED AT ITS PROPOSED $50.9 MILLION EXPENSE FOR UNCOLLECTIBLE ACCOUNTS FOR THE PROJECTED TEST YEAR.

A. Company witness Jason Sparks discusses uncollectible accounts expense beginning on page 20 of his direct testimony and also sponsors Exhibit A-13, Schedule C5.6. The Company started its calculation of the uncollectible expense of $50.9 million for the projected test year by using three years of net write-offs of bad debts to revenues from 2020, 2021, and 2022. Based on the average ratio of 0.78% of net write-offs to revenues for the three years ending in 2022, the Company applied the ratio to projected revenues of $6.311 billion, to calculate an uncollectible account expense of $49.1 million. However, to this result, he added an additional $1.8 million of net write-offs charged directly to other expenses than bad debts expense and increased the total expense to $50.9 million.

Q. WHAT APPROACH DO YOU PROPOSE TO SET UNCOLLECTIBLE ACCOUNTS EXPENSE FOR THE PROJECTED TEST YEAR?

My approach is similar to the Company's, except that I incorporated results for the three years ended 2023 into my analysis based on information received from the Company for 2023.[73] I used the Commission-approved methodology of a three-year average of charge-

[73] DR AGDE-1.27a attachment.

offs to revenues. The Commission has stated in several cases that the use of a three-year average ratio of charge-offs to revenues applied to future revenue is the most appropriate way to forecast uncollectible accounts expense.

Q. WHAT IS YOUR PROJECTED AMOUNT FOR UNCOLLECTIBLE ACCOUNTS EXPENSE FOR THE PROJECTED TEST YEAR?

For the projected test year, I forecasted uncollectible accounts expense of $47.0 million using the three-year historical ratio of net charge offs to revenue for 2021, 2022, and 2023. Exhibit AG-41 shows the net charge-offs for the three-year period of $40.0 million for 2021, $37.7 million for 2022, and $44.1 million for 2023.

Line 4 of the exhibit shows the average percentage of 0.716% as the ratio of net charge-offs to revenue for the three-year historical period. This percentage is multiplied by the projected test year revenues of $6.399 billion on line 5 to derive the forecasted amount of uncollectible accounts expense of $45.8 million on line 6. To this amount, I added average amounts charged directly to other accounts of $1.2 million, which results in a $47.0 million expense forecast for the projected test year. This amount is lower than the Company's forecast by $3.8 million.

Therefore, the Commission should set the uncollectible accounts expense for the projected test year at $47.0 million and reduce the Company's forecasted O&M expense by $3.8 million.

G. Injuries and Damages

Q. THE COMPANY FORECASTED $18.4 MILLION FOR INJURIES AND DAMAGES FOR THE PROJECTED TEST YEAR. DO YOU AGREE WITH THIS AMOUNT?

A. No. On page 3 of Exhibit A-13, Schedule C5.10, the Company developed its forecasted expense for injuries and damages by using the actual expense for the five years ending 2022. This information is now stale. Based upon more recent information available from the Company, I updated the five-year average to incorporate 2023.[74]

Exhibit AG-42 shows the updated calculation for injuries and damages expense. During the past five years the injuries and damages expense has ranged from $5.0 million to $33.0 million. Therefore, the use of the five-year average is a reasonable approach to set the amount of expense for the projected test year given the variability in annual expenses. This methodology has previously been accepted by the Commission.

Based on the most recent five years of actual expenses, I calculated an average expense of $15.577 million. This amount is lower by $2.863 million than the Company's forecast of $18.440 million. Therefore, I recommend that the Commission adopt an Injuries and Damages expense amount of $15.557 million for the projected test year and reduce the Company's forecasted O&M expense by $2.863 million.

[74] DR AGDE-1.38 Attachment.

H. Active Employee Health Care Expense

Q. IN EXHIBIT A-13, SCHEDULE C5.11, THE COMPANY FORECASTED THE ACTIVE EMPLOYEE HEALTH CARE EXPENSE (MEDICAL, DENTAL, AND VISION) AT $56.1 MILLION FOR THE PROJECTED TEST YEAR. DO YOU AGREE WITH THIS AMOUNT?

A. No. The Company's forecasted Active Health Care expense forecast of $56.1 million for the projected test year is an increase of $7.2 million, or 15%, over the adjusted amount of $48.9 million in 2022. There are at least two major problems with the Company's active health care expense projection and the approach taken to forecast the expense. First, the Company continues to apply inflationary factors to historical costs, which it misnames as constant dollar averaging and as a normalization adjustment. This is simply a process that increases actual historical costs in a way that is divorced from reality. This approach has been repeatedly rejected by the Commission, but the Company continues to propose it rate case after rate case.

Second, he uses national health care cost trend rates of 7.0% to 7.5% adjusted down to cost increase rates of 4.0% to 5.1% to forecast future health care costs, instead of using historical health care cost increases actually experienced by the Company. The combination of these factors unnecessarily inflates the forecasted expense for the projected test year.

Q. HAVE YOU CALCULATED A MORE APPROPRIATE EXPENSE FOR HEALTH CARE FOR THE PROJECTED TEST YEAR?

A. Yes. In Exhibit AG-43, I calculated a forecasted expense of $52.9 million for the projected test year. To arrive at this amount, I used information obtained from Exhibit A-13, Schedule C5.11.3, which has the actual average cost of health care per employee from 2017 to 2022 without the constant dollar averaging adjustments.

From the 2017 to 2022 data, I calculated the average rate of increase in healthcare costs of 3.33%. Using this annual rate of increase and applying it to the latest actual costs from 2023, I calculated the projected test year expense of $52.9 million. This expense amount excludes the portion of health care costs that are capitalized. The $52.9 million is a reasonable forecast of health care expenses for the projected test year based on actual cost trends, in contrast with the Company's artificially derived expense of $56.1 million.

I recommend that the Commission approve the $52.9 million of forecasted active health care expense for the test year and remove $3.2 million from the Company's forecasted O&M expense in this case.

I. Supplemental Savings Plan

Q. THE COMPANY HAS INCLUDED $3.2 MILLION OF EXPENSE FOR ITS SUPPLEMENTAL SAVINGS PLAN ON EXHIBIT A-13, SCHEDULE C5.11.

SHOULD THE COMMISSION ACCEPT THIS EXPENSE IN SETTING CUSTOMER RATES?

A. No. Company witness Matthew Fix explains on page 13 of his direct testimony that the Supplemental Savings Plan is for Company employees at the Director level and above, whose contributions to tax qualified benefits is limited due to IRS regulations.

This benefit plan is for a very limited number of highly-paid employees. Customers should not pay for costs that benefit only a select few employees by including these costs in forecasted O&M expense. This plan is similar to the expense for the Supplemental Employee Retirement Plan (SERP), which the Commission has previously rejected.

Therefore, I recommend that the Commission remove the $3.2 million for the Supplemental Savings Plan from the Company's forecasted O&M expense.

J. Private Corporate Jet Travel Costs

Q. PLEASE DISCUSS THE INCLUSION OF CORPORATE JET TRAVEL COSTS IN O&M EXPENSES FOR THE PROJECTED TEST YEAR.

A. In discovery, the Attorney General asked the Company to report the cost and use of privately hired corporate jet aircraft by Company employees or employees of the parent company and affiliates who bill the Company for reimbursement of those costs. In response, the Company reported that it leases a fractional share of an aircraft for use by executives at the Vice President level and above for business travel.

The information provided by the Company shows that several executives of the Company, DTE Gas, and DTE Energy, along with certain members of DTE's Board of Directors took 16 trips on the corporate leased aircraft in 2022 to investor and security analyst meetings and conferences, as well as to out of state Board of Directors meetings. The portion of the cost billed to the Company in 2022 was $236,299 and in 2023 was $139,026. In the discovery response the Company stated that $258,000 of expense was included in the projected test year in this rate case.[75]

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Commission disallow recovery of costs for privately-hired corporate jet use, particularly since the travel pertains to investor and board of director matters that do not directly benefit customers but instead may benefit shareholders. Although commercial flights may be less convenient, they are less costly and less impactful on the environment relative to the emissions of private jets for the few individuals that they carry. In 2020, DTE Energy announced its goal of achieving net zero emissions by 2050. Private jet travel certainly goes counter to that goal.

Therefore, I recommend that the Commission remove the $258,000 of costs that the Company reported it included in the projected test year.

[75] Exhibit AG-47 includes DR AGDG-1.24.

K. Incentive Compensation Expense

Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE COMPANY'S INCENTIVE PAY PLANS AND THE AMOUNT OF EXPENSE THE COMPANY SEEKS TO RECOVER IN THIS RATE CASE.

A. In this rate case covering the projected test year for the twelve months ending December 2025, the Company seeks to recover $59.5 million of employee incentive payments. Based upon the information provided on page 39 of the direct testimony of Mr. Fix, $8.8 million pertains to the Annual Incentive Plan (AIP), $30.3 million to the Rewarding Employees Plan (REP), and $20.4 million pertains to the Long-Term Incentive Plan (LTIP).

2023 Annual Incentive Plan – for DTE Electric (excluding Nuclear) the AIP is an annual bonus program focused on the following major categories and specific measures:

1. 40% on Financial Performance (DTE Electric Earnings, DTE Electric Cash From Operations, and DTE Energy Earnings per Share).
2. 20% on Customer Satisfaction (MPSC Complaints and Net Promoter Score).
3. 15% on Employee Engagement (DTE Electric Employee Engagement, DTE Electric OSHA Incident Rate, and DTE Energy High Energy or Fatality Rate).
4. 25% on Operating Excellence (SAIDI Excluding MEDS, Nuclear On-Line Reliability Loss, Generation Availability, and Customers Experiencing Multiple Interruptions (CEMI).

The operating measures for the nuclear employees are substantially similar, except that 65% of the weight is based on Operating Excellence, zero weight on Customer Satisfaction, 15% on Safety and Engagement, and only 20% is based on Financial Performance.

These measures described above are for the year 2023. A review of the measures in place for the prior five years reveals that certain measures and target levels have varied from year to year. These changes make a direct comparison over the years more challenging.

2023 Rewarding Employees Plan – The REP is very similar in design and function to the AIP with some variations in the non-financial measures. Where the AIP is designed for senior level managers at DTE Electric and its affiliates, the REP covers all other employees of these companies.

Both the AIP and REP are also applied to DTE Energy Corporate Services employees providing support services to DTE Electric.

2022 Long Term Incentive Plan – The LTIP for DTE Electric and for DTE Energy Corporate Services employees is an annual performance unit and stock grant plan focused primarily on achieving multi-year goals and specifically on the following measures:

1. 80% on Common Stock Total Shareholder Return vs. a Peer Group.
2. 20% Three Year Cumulative Operating EPS.

For employees in the Company's Nuclear Division, the financial goals are a 20% weighting, and the "on-line Reliability Loss Factor" and "INPO Index" represent 80% of the weighting.

The testimony of Company witness Matthew Fix provides more details on the AIP, REP, and LTIP.

Q. WHAT IS YOUR ASSESSMENT OF EACH OF THESE INCENTIVE PAY PLANS?

A. My overall assessment is that the three incentive plans are too heavily skewed toward measures that directly benefit shareholders and not customers. In this regard, page 39 of Mr. Fix's testimony shows that $39.2 million out of the $59.5 million of incentive compensation expense requested pertains to the Company's financial metrics. Additionally, the customer benefits presented by the Company are based on a faulty premise of historical cost savings and an expectation that future targets of performance will be achieved.

With regard to the AIP and REP, nearly half of the incentive payout at target level relates to DTE Energy achieving operating earnings per share and cash flow goals. Despite the argument by the Company that achieving these goals somehow benefits customers, there is no direct relationship to customer benefits. These goals are in place to maximize profits and increase cash flow to pay dividends to shareholders. It is even more inappropriate to charge customers for incentive pay costs related to achieving DTE Energy earnings, since they are based in part on earnings from the gas and non-utility businesses of DTE Energy.

The Commission should not allow recovery of incentive payments related to these financial goals.

As to the Customer Satisfaction grouping of measures, this category in 2023 represents just 20% of the total weighting.

With regard to the Employee Engagement category, the measures contained therein, although worthy goals, do not rise to the level of being measures that are visible to customers nor do they create direct customer benefits. They are primarily internal goals related to employee satisfaction and deployment of safe practices in the workplace.

As to the Operating Excellence category, the measures contained therein are basic operating goals. Again, these are worthy internal goals to measure performance of the departments responsible for those operations, but they have no direct visibility to customers. The only measures that have a direct link to customers are the Electric outage metrics (SAIDI excluding MEDS) and the metrics addressing multiple customer outages, which represent a small portion of the expected payout. Moreover, improvements in this area will be largely a function of a more aggressive tree trimming program and capital spending programs, which are paid for through increases in customer rates.

Q. **WHAT IS YOUR ASSESSMENT OF THE LTIP?**

A. The LTIP is a plan strictly designed to induce management to create shareholder value. It is weighted heavily (80%) on total shareholder return, which is stock price appreciation

and dividends paid over a period of time. The Company's total return is then measured against a group of peer companies to trigger a payout. This has nothing to do with creating direct benefits for DTE Electric customers and everything to do with creating value for DTE Energy shareholders. Similarly, the other measure, DTE Electric return on equity, is also very removed from any quantifiable benefits that directly accrue to customers. To some degree this last item is actually duplicative of the Operating Earnings and Cash Flow measures included in the AIP and REP plans.

The arguments that some of these measures will create a healthier company and therefore customers should pay for LTIP expenses are not convincing.

Q. **WHAT IS YOUR OPINION OF THE CUSTOMER BENEFITS CALCULATED BY MR. FIX TO JUSTIFY RECOVERY OF THE INCENTIVE PAYMENTS?**

A. In Exhibit A-21, Schedule K6, Mr. Fix included a calculation that purports to show that recent operating and financial cost savings are exceeding adjusted incentive plan payments by $45.0 million. However, the largest benefits showing in this exhibit are in the areas of (1) Safety ($9.5 million); (2) Operating Excellence ($58.4 million), with a large part of this category being highly dependent upon a more aggressive tree trimming program and capital spending program, which should in turn reduce the SAIDI outage metric; and (3) $20.4 million of benefits related to Employee Engagement Gallup results, whereby better employee survey results should (according to Gallup) lead to reduced absenteeism, higher productivity, and a better safety record.

Q. PLEASE COMMENT ON THE COMPANY'S PERFORMANCE ON THE OPERATING METRICS IN 2023.

A. In response to discovery, the Company provided the results of the incentive performance measures for the year 2023. The 2023 results show that DTE Electric's performance on 7 of the 9 metrics was below target. Nuclear Generation's performance measures were below target in 4 of the 8 metrics, and DTE LLC's performance was below target in 7 of the 8 metrics.[76] On average in 2023, target performance was reached for only one-third of the performance metrics.

Q. DO THE 2023 PERFORMANCE LEVELS RAISE UNCERTAINTY WITH RESPECT TO WHAT WILL BE PAID OUT UNDER THE INCENTIVE PLANS DURING THE PROJECTED TEST YEAR PERIOD?

A. Yes. Mr. Fix stated on page 39 of his testimony that the $59.5 million of incentive compensation expense is based on "Target" performance levels. Therefore, if the Company's sub-standard performance levels continue into the projected test period, then a substantial portion of the incentive payments anticipated by Mr. Fix will not happen.

As shown in Exhibit AG-21, the Company has not been able to meet 100% of the operating performance targets in the past five years. Accordingly, 2023 was not a one-year anomaly. Mr. Fix's testimony and exhibits provide little assurance that all operating performance

[76] Exhibit AG-21 includes DR AGDE-1.48 with attachment.

measures can be achieved at 100% of target level in the future with any consistency, as he has assumed in calculating the incentive compensation expense that the Company seeks to recover in this case.

In summary, my assessment is that the Company has failed to show that it has achieved consistent performance at target levels to justify recovery of 100% of incentive pay expenses relating to the operating performance measures.

Q. **WHAT IS YOUR RECOMMENDATION WITH REGARD TO INCENTIVE PAYMENTS BEING RECOVERED IN CUSTOMER RATES?**

A. On page 39 of his direct testimony, Mr. Fix has included a table showing the components of the incentive compensation expense that the Company has included in the O&M expense for the projected test year. For the reasons described above, I recommend that the Commission remove the entire $39.2 million related to financial performance measures.

With regard to the portion of incentive compensation relating to operating measures, my initial instinct is to also disallow this portion in its entirety, as I have recommended in several prior cases, due to the fact that the Company has not made a sufficiently compelling case to justify recovery of these costs. However, I am cognizant of the fact that the Commission has in recent cases allowed recovery of a portion of the short-term incentive pay related to operating performance measures for DTEE and Consumers Energy. In that vein, I recommend that the Commission allow recovery of a portion of incentive compensation expense pertaining to operating performance measures.

In DR AGDE-1.48, included in Exhibit AG-21, the Company calculated the percentage of non-financial metrics achieved at target or better over the past five years ending in 2023. The overall percentage achieved by the three organizations over the five-year period is approximately 47.4%. The total amount of incentive compensation calculated by the Company at target for operating measures relating to the incentive compensation plans is $20,271,000, as shown in Table 3, on page 39 of Mr. Fix's direct testimony. Therefore, I recommend that the Commission only approve recovery of incentive compensation expense for 47.4% of the $20,271,000, or $9,608,000, and disallow recovery of the remaining $10,663,000 for the operational metrics. This amount, plus the $39,232,000 disallowance related to financial metrics, results in a total disallowance of $49,895,000 of the $59.5 million of incentive compensation expense proposed by the Company in this case. In addition, as discussed in the Working Capital section of my testimony and shown in Exhibits AG-20 and AG-44, the Commission needs to remove $1,358,000 of negative amortization expense from excess compensation expense paid in the 2023 projected test year in Case No. U-20836. Therefore, the total reduction in incentive compensation expense is $51,253,000.

L. O&M Expense Summary

Q. WHAT ARE THE TOTAL ADJUSTMENTS THAT YOU RECOMMEND TO THE COMPANY'S FORECASTED O&M EXPENSES?

A. I recommend total reductions to O&M expenses of $123.5 million as discussed above. Exhibit AG-20 and the table below provide a summary of the areas where I proposed O&M expense adjustments.

Summary of O&M Expense Reductions	Amount ($Millions)
Inflation Adjustments	$ 14.6
Steam Generation Expense	21.9
Voluntary Separation Program	10.1
Tree Trimming Surge Savings	8.8
Merchant Credit Card Fees	3.5
Uncollectible Accounts Expense	3.8
Injuries & Damages Expense	2.9
Active Health Care	3.1
Supplemental Savings Plan	3.2
Corporate Aircraft	0.3
Employee Incentive Compensation	51.3
Total Reduction	**$123.5**

VIII. Depreciation Expense

Q. **DO YOU PROPOSE AN ADJUSTMENT TO DEPRECIATION EXPENSE FOR THE PROJECTED TEST YEAR?**

A. Yes. As a result of the reductions in capital expenditures proposed above in my testimony and the impact on capital additions included in rate base, I have calculated a reduction in depreciation expense of $40,788,000. The calculation of this amount is shown in Exhibit AG-18 and is based on the same depreciation rates used by the Company on page 2 of Exhibit A-13, Schedule C6.

I recommend that the Commission reduce the depreciation expense proposed by the Company for the projected test year by $40,788,000.

IX. Property Tax Expense

Q. PLEASE DISCUSS THE PROPERTY TAX EXPENSE ADJUSTMENT THAT YOU PROPOSE.

A. In Exhibit AG-18, I identified the adjustments to be made to the Company's proposed capital expenditures. Those reductions lower the amount of property tax expense that the Company will incur during the projected test year. On the same exhibit, I have calculated the reduction in property tax expense of $12,261,000. I recommend that the Commission reduce the Company's property tax expense by this amount for the projected test year.

X. Adjustments To Revenue Deficiency

Q. WHAT ARE THE TOTAL ADJUSTMENTS AND THE REVISED REVENUE DEFICIENCY YOU RECOMMEND?

A. Exhibit AG-48 summarizes the adjustments to rate base and operating income. The net result is a revised revenue deficiency of $139.5 million, which is a reduction of $316.9 million from the Company's requested level of $456.4 million.

I recommend the Commission adopt these adjustments and issue an order granting rate relief to the Company in an amount not exceeding $139.5 million.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes, it does. However, I reserve the right to amend, revise and supplement my testimony to incorporate new information that may become available.

Appendix A

Experience and Qualifications of Sebastian Coppola

Mr. Sebastian Coppola is an independent energy business consultant and president of Corporate Analytics, Inc., whose place of business is located at 5928 Southgate Rd., Rochester, Michigan 48306.

EMPLOYMENT BACKGROUND

Mr. Coppola has been an independent consultant for 22 years. Before that, he spent three years as Senior Vice President and Chief Financial Officer of SEMCO Energy, Inc. with responsibility for all financial operations, corporate development and strategic planning for the company's Michigan and Alaska regulated and non-regulated operations. During the period at SEMCO Energy, he had also responsibility for certain storage and pipeline operations as President and COO of SEMCO Energy Ventures, Inc. Prior to SEMCO, Mr. Coppola was Senior Vice President of Finance for MCN Energy Group, Inc., the parent company of Michigan Consolidated Gas Company (now DTE Gas Company).

ENERGY INDUSTRY EXPERTISE

During his 27-year career at SEMCO Energy, MCN Energy and MichCon, Mr. Coppola held various analytical, accounting, managerial and executive positions, including Manager of Gas Accounting with responsibility for maintaining the accounting records and preparing financial reports for gas purchases and gas production. In this role, he had also responsibility for preparing Gas Cost Recovery (GCR) reconciliation analysis and reports, and supporting preparation of testimony for the cost of gas reconciliation proceedings before the MPSC. Over the years, Mr. Coppola also held the positions of Treasurer, Director of Investor Relations, Director of Accounting Services, Manager of Corporate Finance, Manager of Customer Billing and Manager of Materials Inventory and Warehousing Accounting. In many

of these positions he interacted with various operating areas of the company and was intricately involved in construction and operating programs, defining gas purchasing strategies, rate case analysis, cost of capital studies and other regulatory proceedings.

Mr. Coppola is intricately knowledgeable of capital markets and financial institutions. As Treasurer and Vice President of Finance, he directed the issuance of more than $2 billion in securities, including common stock, corporate bonds, tax-deductible preferred stock and high-equity value convertible securities. He established bank lines of credit, commercial paper and asset acquisition facilities. He has had extensive interactions with equity and debt investors, financial analysts, rating agencies and other members of the financial community.

ENERGY INDUSTRY AND REGULATORY EXPERIENCE

As a business consultant, Mr. Coppola specializes in financial and strategic business issues in the fields of energy and utility regulation. He has more than forty years of experience in public utility and related energy work, both as a consultant and utility company executive. He has testified in several regulatory proceedings before State Public Service Commissions. He has prepared and/or filed testimony in electric and gas general rate case proceedings, power supply and gas cost recovery mechanisms, revenue and cost tracking mechanisms/riders, multi-year rate plans and incentive ratemaking, and other regulatory matters.

Mr. Coppola has extensive experience with gas and electric utilities in the areas of gas operations, gas supply and regulatory proceedings. He has led or participated in the financial operations, gas supply planning and/or gas cost recovery arrangements of two major gas utilities in Michigan and in Alaska. He has prepared

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testimony in multiple electric and gas general rate cases, Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) reconciliation proceedings, Cast Iron and Pipeline Replacement Programs and other regulatory cases on behalf of the Michigan Attorney General, Citizens Against Rate Excess (CARE), the Public Counsel Division of the Washington Attorney General, the Illinois Attorney General, the Maryland Office of Public Counsel, and the Ohio Office of Consumers Counsel in electric and gas utility rate cases, including AEP Ohio, Ameren-Illinois Utilities, Avista, Consumers Energy, DTE Electric Company, MichCon (DTE Gas Company), Michigan Gas Utilities Corp, Nicor Gas, PacifiCorp, Peoples Gas, Puget Sound Energy, SEMCO, Upper Peninsula Power Company, Washington Gas, and Wisconsin Public Service Company.

Mr. Coppola has also provided assistance and proposals to the Maryland Office of Peoples Counsel on Multi-Year Rate Plans and Performance-Based Ratemaking. Additionally, he prepared a report on the financial condition and risks of AltaGas and Washington Gas Light Company which was filed with the Maryland Public Service Commission in July 2019 in Case No. 9449.

As accounting manager and later financial executive for two regulated gas utilities, he has been intricately involved in construction materials procurement, gas purchase strategies and CGR reconciliation cases. He has had direct responsibility for preparing GCR reconciliation analysis and reports, and supporting preparation of testimony for the cost of gas reconciliation proceedings before the Michigan Public Service Commission (MPSC). He is intricately familiar with construction projects, the power supply and gas cost recovery mechanisms, gas supply and pricing issues, and regulatory issues faced by utilities.

Experience and Qualifications of Sebastian Coppola

During his long career at DTE Gas, among other responsibilities, Mr. Coppola was responsible to oversee the operation of the MichCon Wet Header System, a pipeline that transported natural gas and gas liquids from Michigan gas producing fields in the Niagaran Reef in the northern area of the lower peninsula of Michigan to processing plants in Kalkaska, MI. His responsibility included ensuring the day-to-day flow of gas and liquids, and identifying operating issues requiring corrective action.

He was also responsible for the study to assess the feasibility of building the Saginaw Bay Pipeline, a transmission line to move Praire Du Chein natural gas reserves in the eastern area of Michigan to processing plants. Prior to the construction of the pipeline, Mr. Coppola worked with operating management to prepare requests for proposal for the construction project and the selection of qualified bids. During and subsequent to the construction of the pipeline, Mr. Coppola assisted in the management and oversight of the pipeline, including review of operating performance and profitability.

Additionally, as Manager of Materials Inventory, Warehousing and Procurement at DTE Gas, Mr. Coppola worked closely with suppliers of pipe, control valves, flanges, meters, fittings, equipment and thousands of other parts and materials used in the construction, repair and maintenance of DTE Gas's transmission, distribution and storage facilities, including repairs and upgrades to compressor stations, and replacement of cast iron mains, bare and wrapped steel pipelines and service lines. His responsibilities included the review of design and construction blueprints and plans with frequent visits to construction sites during excavation of new pipeline trenches, and during replacement of defective or leaky

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pipes, and replacement of control valves. Mr. Coppola also made frequent visits and inspection to storage facilities owned by DTE Gas to understand materials requirements during planned construction projects. Mr. Coppola was also responsible to ensure that materials and equipment were ordered to meet material standards and safety codes.

Through these responsibilities, Mr. Coppola gained knowledge and expertise with field construction project procedures, pipeline trenching problems, installation inspections, operation and maintenance cycles, and the material procurement of pipe, valves, flanges, meters and thousands of other parts and equipment used in the construction of natural gas transmission, distribution and storage facilities.

During his career with MCN Energy Group, Mr. Coppola was responsible for the evaluation of investments in interstate pipelines, new gas storage facilities, gas cogeneration plants, and construction of new power plants in the U.S. and India. Mr. Coppola was a key member of the negotiating team with contractors and suppliers tasked to build the power facilities, including the evaluation of Engineering, Procurement and Construction (EPC) bids and contracts.

Subsequent to his move to SEMCO Energy Corporation in 1999, Mr. Coppola was responsible for the acquisition and integration of pipeline construction companies providing services to gas utilities and interstate pipelines. In addition to its gas utility business in Michigan and Alaska, serving approximately 350,000 customers, SEMCO Energy owned SEMCO Pipeline Construction, a non-regulated business providing gas pipeline and natural gas facilities construction services to gas utilities and interstate pipelines in the Midwest and Eastern regions of the U.S.

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SEMCO Pipeline Construction provided construction services similar to KS Energy, Northern Pipeline and other contractors used by the Company. During his tenure at SEMCO Energy, Mr. Coppola reviewed dozens of pipeline construction companies and acquired six companies. Mr. Coppola's responsibilities included management of the performance and profitability of the pipeline construction services business requiring field visits to construction projects and quality reviews. In this process, Mr. Coppola learned firsthand how pipeline construction companies operate, construction project challenges, their bidding practices and the bidding of construction projects, including pricing, bidding procedures and policies both from the contractor's side and the gas utility side.

Mr. Coppola has testified extensively on gas utility pipeline, service lines and inside meters replacement programs related to at-risk pipes that provide safety issues to customers and the general public.

In his role as Treasurer and Chairman of the MCN/MichCon Risk Committee from 1996 through 1998, Mr. Coppola was involved in reviewing and deciding on the appropriate gas purchase price hedging strategies, including the use of gas future contracts, over the counter swaps, fixed price purchases and index price purchases.

In March 2001, Mr. Coppola testified before the Michigan House Energy and Technology Subcommittee on Natural Gas Fixed Pricing Mechanisms. Mr. Coppola frequently participates in natural gas issue forums sponsored by the American Gas Association and stays current on various energy supply issues through review of industry analyst reports and other publications issued by various trade groups.

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Mr. Coppola performed rate case analyses and filed testimony in several electric general rate cases addressing issues on revenue requirement, sales level determination, operation and maintenance expenses, capital expenditures, cost allocations, cost of capital, cost of service and rate design, and various cost tracking mechanisms. In addition, he has performed analysis of power costs and filed testimony in power supply cost recovery cases, including reconciliation of annual power supply costs.

In his position as Senior Vice President of Finance at MCN, Mr. Coppola also had responsibility for project financing of independent power generation plants in which MCN was an owner. In this regard, he was intricately involved and became knowledgeable of PURPA qualified cogeneration plants in Michigan and other states. In addition, he was involved in negotiating the development and financing of power generation and electricity distribution plants in other countries, such as India.

- **Specific Regulatory Proceedings and Related Experience:**
  - Filed testimony on behalf of the Michigan Attorney General in the Upper Peninsula Power Company (UPPCO) 2024 gas rate case U-21555 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
  - Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2024 gas rate case U-21540 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
  - Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.
  - Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2024 gas rate case U-21291 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
  - Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2022-2023 GCR reconciliation in case No. U-21065.

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- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy (CECo) 2023 gas rate case U-21490 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTM Michigan Lateral Company (DMLC) 2023 Act 9 Transportation Service rate update in case No. U-21525.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2022 PSCR reconciliation in case No. U-21051.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2022-2023 GCR plan in case No. U-21067.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 PSCR reconciliation in case No. U-21049.
- Filed testimony on behalf of the Michigan Attorney General in Indiana Power Company 2023 electric rate Case U-21461 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE 2023-2024 GCR plan in case No. U-21271.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023-2024 GCR plan in case No. U-21269.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 electric rate Case U-21389 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2023 rate Case U-21297 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2023-2024 GCR plan in case No. U-21273.

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- Filed testimony on behalf of the Michigan Attorney General in CECo 2022 gas rate Case U-21308 on several issues, including sales revenues, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-2022 GCR plan reconciliation case No. U-20817.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2021 PSCR plan reconciliation case No. U-20827.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2021-2022 GCR plan reconciliation case No. U-20819.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2022 general rate case No. U-21286.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-2022 GCR plan reconciliation case No. U-20823.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022-2023 GCR plan case No. U-21062.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2022-2023 GCR plan case No. U-21070.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022 electric rate Case U-21224 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Public Counsel Division of Washington Attorney General in the Avista 2022 electric and gas rate cases on several issues, including operation and maintenance expenses, capital expenditures, and other items.
- Filed testimony on behalf of the Michigan Attorney General in the Act 9 application in Case No. U-20993 by Saginaw Bay Pipeline Company to set transportation rates for services to DTE Gas Company.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2022 electric rate Case U-20836 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.

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- Filed rebuttal testimony on behalf the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gaslight & Coke Company (Peoples Gas) in Docket 17-0137.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2021 gas rate Case U-21148 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2020-2021 GCR plan reconciliation case No. U-20554.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 20-0330.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2020-2021 GCR plan reconciliation case No. U-20552.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2020-2021 GCR plan reconciliation case No. U-20546.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2020 PSCR plan reconciliation case No. U-20526.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2020 PSCR plan reconciliation case No. U-20528.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2019-2020 GCR plan reconciliation case No. U-20236.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Ameren Illinois Company (Ameren) in Docket 20-0323.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-2022 GCR plan case No. U-20816.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-2022 GCR plan case No. U-20822.

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- Filed testimony on behalf of the Michigan Attorney General in CECo 2021 electric rate Case U-20963 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021 gas rate Case U-20940 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Michigan Lateral Company (DMCL) 2021 Act 9 filing to convert a pipeline and build two interconnections for transportation services to DTE Gas Company in case No. U-20894.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2021 power plant and tree trimming securitization costs in case No. U-21015
- Filed testimony on behalf of the Michigan Attorney General in CECo 2021 PSCR plan case No. U-20802.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2019-2020 GCR reconciliation case No. U-20234.
- Filed testimony on behalf of the Maryland Office of Public Counsel in Washington Gas Light Company's 2020 rate Case 9651 on several issues, including operation and maintenance expenses, capital expenditures, and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2020 Karn 1 & 2 Retirement Cost and Bond Securitization Case U-20889.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Reconciliation in case U-20222.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2020-2021 GCR plan case No. U-20543.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Gas Company (SEMCO) 2020-2021 GCR plan case No. U-20551.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2020 electric rate Case U-20697 on several issues, including operation

and maintenance expenses, capital expenditures, cost of capital, and other items.

- Filed testimony on behalf of the Michigan Attorney General in in the complaint against Upper Peninsula Power Company's (UPPCO) Revenue Decoupling Mechanism (RDM) in Case No. U-20150.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2019 gas rate Case U-20650 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company 2019 gas rate Case U-20642 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018-2019 GCR reconciliation Case U-20210.
- Prepared a report on the financial condition and risks of AltaGas and Washington Gas Light Company on behalf of the Maryland Office of People's Counsel filed with the Maryland Public Service Commission in July 2019 in Case No. 9449.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018-2019 GCR reconciliation case U-20209.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2018-2019 GCR reconciliation case U-20215.
- Provided assistance and proposals to the Maryland Office of Peoples Counsel on Multi-Year Rate Plans and Performance-Based Ratemaking.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 PSCR Reconciliation in case U-20203.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 PSCR Reconciliation in case U-20202.

Experience and Qualifications of Sebastian Coppola

- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 electric rate Case U-20561 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in Indiana Michigan Power Company (I&M) 2019 electric rate Case U-20239 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019 gas rate Case U-20479 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019-2020 GCR Plan case U-20245.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2019-2020 GCR Plan case U-20233.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Plan case U-20221.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2019-2020 GCR Plan case U-20235.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2019-2020 GCR plan case U-20239.
- Filed rebuttal testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017-2018 GCR reconciliation case U-20076.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in CECo 2017-2018 GCR reconciliation case U-20075.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 gas rate Case U-20322 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in I&M Tax Credit C Calculation in case U-20317.
- Filed direct testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Tax Credit C Calculation in case U-20298.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2017-2018 GCR Reconciliation case U-20078.
- Filed testimony on behalf of the Michigan Attorney General in CECo Tax Credit C Calculation for the Gas and Electric Divisions in case U-20309.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2018 electric rate Case U-20276 on several issues, including excess deferred taxes, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 PSCR Reconciliation in case U-20068.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 rate Case U-20162 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit B refund for the Electric Division in case U-20286.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Integrated Resource Plan in case U-20165.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit B refund case U-20287 for the natural gas business.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit B refund case U-20189.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 electric rate Case U-20134 on several issues, including capital expenditures, cost of capital, rate design and other items.
- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 16-0197.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR reconciliation case U-17941-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2018-2019 GCR Plan case U-18417.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit A refund case U-20102.
- Filed testimony on behalf of the Michigan Attorney General in I&M 2018 PSCR Plan case U-18404.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018-2019 GCR Plan case U-18412.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company (UPPCO) 2018 Tax Credit A refund case U-20111.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit A refund case U-20106.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 PSCR Plan case U-18403.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 PSCR Plan case U-18402.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017 gas rate Case U-18999 on several issues, including revenue,

operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.

- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 gas rate Case U-18424 on several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 PSCR reconciliation case U-17918-R.
- Assisted the Michigan Attorney General in the review of several GCR and PSCR cases during 2017 and 2018, and proposed terms for settlement of those cases.
- Assisted the Michigan Attorney General in the filing of comments with the Michigan Public Service Commission relating to rate case filing requirements in case U-18238, refunds of tax savings from the lower federal tax rate in case U-18494 and Performance Based Regulation.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 15-0209.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 electric Rate Case U-18255 on a several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 electric rate Case U-18322 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital and other items.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the re-opening of proceedings in the restructuring of the Peoples Gas's main replacement program and gas system modernization plan in Docket 16-0376.
- Filed testimony on behalf of the Michigan Attorney General in the Upper Michigan Energy Resources Corporation (UMERC) application for a certificate of public necessity and convenience to build two power plants in the Upper Peninsula of Michigan in case U-18202.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in SEMCO application for a certificate of public necessity and convenience to build a pipeline in the Upper Peninsula of Michigan in case U-18202.
- Filed testimony on behalf of the Public Counsel Division of the Washington Attorney General in Puget Sound Energy's 2016 Complaint for Violation of Gas Safety Rules in Docket No. UE-160924.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 PSCR Plan case U-18143.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 Power Supply Cost Recovery (PSCR) reconciliation case U-17678-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 gas general rate case U-18124 on a several issues, including revenue, operations and maintenance costs, capital expenditures, working capital, cost of capital and other items.
- Filed testimony on behalf of the Illinois Attorney General for the restructuring of the Peoples Gas's main replacement program in Docket 16-0376.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2014-2015 GCR Plan reconciliation case U-17332-R.
- Filed testimony on behalf of the Michigan Attorney General in the formation of UMERC and the transfer of Michigan assets of Wisconsin Public Service Corporation and Wisconsin Electric Company to UMERC in Case U-18061.
- Filed testimony on behalf of the Michigan Attorney General in CECo Court of Appeals Remand Case U-17087 for review of the Automated Meter Infrastructure (AMI) opt-out fees.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 electric Rate Case U-17990 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital, rate design and other items.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2016-2017 GCR Plan case U-17940.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 electric Rate Case U-18014 on a several issues, including revenue, revenue decoupling, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2016-2017 GCR Plan case U-17942.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR Plan case U-17941.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2015 gas general rate case U-17999 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, Revenue Decoupling Mechanism (RDM) program, cost of capital and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016-2017 GCR Plan case U-17943.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 PSCR Plan case U-17918.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014-2015 GCR Plan reconciliation case U-17334-R.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 PSCR Plan case U-17920.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan reconciliation case U-17333-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 gas general rate case U-17882 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, infrastructure cost recovery mechanism, cost of capital and other items..
- Filed testimony on behalf of the Michigan Attorney General in CECo Gas Choice and End-User Transportation tariff changes case U-17900.

Experience and Qualifications of Sebastian Coppola

- Analyzed the gas rate case filings of MGUC in Case U-17880 and assisted the Michigan Attorney General in settlement of the case.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 PSCR reconciliation case U-17317-R.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2013-2014 GCR Plan reconciliation case U-17131-R.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2014 electric Rate Case U-17767 on a several issues, including operations and maintenance costs, capital expenditures, AMI program, cost of capital and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2015-2016 GCR Plan case U-17691.
- Filed testimony on behalf of the Illinois Attorney General in Ameren Illinois Company's 2015 general rate case on operation and maintenance costs in Docket 15-0142.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 electric Rate Case U-17735 on a several issues, including sales, operations and maintenance costs, capital expenditures, cost of capital, AMI program, revenue decoupling and infrastructure cost recovery mechanisms.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015-2016 GCR Plan case U-17693.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2015-2016 GCR Plan case U-17690.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 PSCR Plan case U-17678.
- Analyzed the electric rate case filings of Northern States Power in Case U-17710 and Wisconsin Public Service Company U-17669, and assisted the Michigan Attorney General in settlement of these cases.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2013-2014 GCR Plan reconciliation case U-17133-R.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan reconciliation cases U-17130-R.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan reconciliation case U-17132-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 gas general rate case U-17643 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, cost of capital and other items..
- Filed testimony on behalf of the Illinois Attorney General in Wisconsin Energy merger with Integrys on the Peoples Gas and Coke Company's Accelerated Main Replacement Program Docket 14-0496.
- Filed testimony on behalf of Citizens Against Rate Excess in Wisconsin Public Service Company's 2013 PSCR plan reconciliation case U-17092-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 PSCR plan case U-17317.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 OPEB Funding case U-17620.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan case U-17333.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2014-2015 GCR Plan case U-17331.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014-2015 GCR Plan case U-17334.
- Filed testimony for Citizens Against Rate Excess in Wisconsin Public Service Company's 2014 PSCR plan case U-17299.
- Filed testimony in March 2013 on behalf of the Michigan Attorney General in CECo's electric Rate Case U-15645 on remand from the Michigan Court of Appeals for review of the AMI program.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 PSCR plan case U-17298.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2012-2013 GCR Reconciliation case U-16920-R.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company 2012-2013 GCR Reconciliation case U-16921-R.

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- Filed testimony on behalf of the Michigan Attorney General in CECo 2012-2013 GCR Reconciliation case U-16924-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2012-2013 GCR Reconciliation case U-16922-R.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) reconciliation case U-16881-R.
- Filed testimony in Puget Sound Energy's 2013 Power Cost Only Rate Case on behalf of the Public Counsel Division of the Washington Attorney General in Docket No. UE-130167 on the power costs adjustment mechanism.
- Filed testimony in PacifiCorp's 2013 General Rate Case on behalf of the Public Counsel Division of the Washington Attorney General in Docket No. UE-130043 on power costs, cost allocation factors, O&M expenses and power cost adjustment mechanisms.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan case U-17132.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan case U-17130.
- Filed testimony on behalf of the Michigan Attorney General in CECo's 2012 electric Rate Case U-17087 on a several issues, including cost of service methodology, rate design, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism and other revenue/cost trackers.
- Filed reports on gas procurement and hedging strategies of four gas utilities before the Washington Utilities and Transportation Commission on behalf of the Washington Attorney General – Office of Public Counsel in April 2013.
- Filed testimony on behalf of the Michigan Attorney General in MGUC and SEMCO 2011-2012 GCR Plan reconciliation cases U-16481-R and U-16483-R.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) plan case U-17091.

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- Filed testimony in MichCon's 2012 gas Rate Case U-16999 on a several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism.
- Filed testimony on behalf of the Washington Attorney General – Office of Public Counsel on executive and board of directors' compensation in the 2012 Avista general rate case.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2011 Power Supply Cost Recovery (PSCR) reconciliation case U-16421-R.
- Filed testimony on behalf of the Ohio Office of Consumers Counsel in AEP Ohio's power supply restructuring case in June 2012.
- Filed testimony on behalf of the Michigan Attorney General in MGUC and SEMCO 2012-2013 GCR Plan cases U-16920 and U-16922.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 PSCR plan case U-16881.
- Filed testimony for Citizens Against Rate Excess in Wisconsin Public Service Corporation's 2012 PSCR plan case U-16882.
- Filed testimony for the Michigan Attorney General in CECo's gas business Pilot Revenue Decoupling Mechanism in case U-16860.
- Filed testimony for the Michigan Attorney General in Consumers Energy Gas 2011 Rate Case U-16855 on several issues, including sales volumes, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in SEMCO and MGUC 2010-2011 GCR Plan reconciliation cases U-16147-R and U-16145-R.
- Filed testimony for the Michigan Attorney General in Consumers Energy 2011 electric Rate Case U-16794 on several issues, including electric sales forecast, revenue decoupling mechanism, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in CECo's electric business Pilot Revenue Decoupling Mechanism in case U-16566.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in SEMCO and MGUC 2011-2012 GCR Plan cases U-16483 and U-16481.
- Filed testimony for the Michigan Attorney General in Detroit Edison 2010 electric Rate Case U-16472 on several issues, including revenue decoupling mechanism, operations and maintenance cost, executive compensation and benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in SEMCO 2009-2010 GCR reconciliation case U-15702-R.
- Filed testimony for Michigan Attorney General in MGUC 2009-2010 GCR reconciliation case U-15700-R.
- Filed testimony for Michigan Attorney General, in Consumers Energy Gas 2010 Rate Case U-16418 on several issues, including sales volumes, operations and maintenance costs, capital expenditures and cost of capital.
- Filed testimony for Michigan Attorney General, in SEMCO 2010 Rate Case U-16169 on several issues, including sales volumes, rate design, operations and maintenance cost, executive compensation and benefits, capital expenditures and cost of capital.
- Filed testimony, for Michigan Attorney General in Consumers Energy 2009 electric Rate Case U-16191 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost and capital expenditures.
- Filed testimony for Michigan Attorney General, in MichCon 2009 gas Rate Case U-15985 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost, capital expenditures and cost of capital.
- Filed testimony for Michigan Attorney General and was cross-examined in Consumers Energy 2009 gas Rate Case U-15986 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost, capital expenditures and cost of capital.
- Prepared testimony and assisted the Michigan Attorney General in discussions and settlement of SEMCO and MGUC 2010-2011 GCR Plan cases U-16147 and U-16145.

Experience and Qualifications of Sebastian Coppola

- Prepared testimony and assisted Michigan Attorney General in settlement of SEMCO 2009-2010 GCR case U-15702.
- Prepared testimony and assisted Michigan Attorney General in settlement of MGUC 2009-2010 GCR case U-15700.
- Prepared testimony and assisted the Michigan Attorney General in discussions and settlement of SEMCO 2008-2009 GCR case U-15452 and reconciliation case U-15452-R.
- Prepared testimony and assisted Michigan Attorney General in discussions and settlement of MGUC 2008-2009 GCR reconciliation case U-15450-R.
- Prepared testimony for Michigan Attorney General in SEMCO GCR 2007-2008 Reconciliation Case U-15043-R.
- Prepared testimony for Michigan Attorney General filed in MGUC 2007-2008 GCR Reconciliation Case U-15040-R.
- Participated in drafting of testimony for all aspects of SEMCO rate case filing with the Regulatory Commission of Alaska (RCA) in 2001.
- Filed testimony in 2001 before the (RCA) and was cross-examined on the financing plans for the acquisition of Enstar Corporation and the capital structure of SEMCO.
- Developed a cost of capital study in support of testimony by company witness in the Saginaw Bay Pipeline Company rate request proceeding in 1989.
- Prepared testimony for company witness on cost of capital and capital structure in MichCon 1988 gas rate case.
- Filed testimony in MichCon gas conservation surcharge case in 1986-87.
- Testified before MPSC ALJ in MichCon customer bill collection complaints in 1983.
- Participated in analysis of uncollectible gas accounts expense for inclusion in rate filings between 1975 and 1988.
- Participated in analysis of allocation of corporate overhead to subsidiaries and use of the “Massachusetts Formula” at MichCon and at SEMCO in 1975 and 2000.

Experience and Qualifications of Sebastian Coppola

- Prepared support information on GCR and rate case-O&M testimony at MichCon from 1975 to 1988.
- Filed testimony in MichCon financing orders in 1987 and 1988.
- Participated in rate case filing strategy sessions at MichCon and SEMCO from 1975 to 2001.
- Provided Hearing Room assistance and guidance to counsel on financial and policy issues in various cases from 1975 to 2001.

EDUCATIONAL BACKGROUND

Mr. Coppola did his undergraduate work at Wayne State University, where he received the Bachelor of Science degree in Accounting in 1974. He later returned to Wayne State University to obtain his Master of Business Administration degree with major in Finance in 1980.



JUDGE WALLACE: Off the record for just a second. Just a second off the record.

(At 11:49 a.m., brief discussion.)

JUDGE WALLACE: I'm sorry, Mr. King. Back on the record.

MR. KING: Thank you, your Honor. Nothing further from the Attorney General at this time.

JUDGE WALLACE: Thank you, Mr. King. Next, Mr. Bzdok or Ms. Andrews for MNSC.

MS. ANDREWS: Good afternoon, your Honor. Is it after -- good morning still. My apologies.

On behalf of the Citizens Utility Board of Michigan and the Michigan Environmental Council, I would move to bind in the Direct Testimony Matthew Bandyk, which consists of a cover page, table of contents, 24 pages of question and answers; and I would also move for the admission into the record of Exhibits CUB-1 through CUB-10, which were sponsored by Mr. Bandyk.

JUDGE WALLACE: O.K. Is there any objection to binding in the direct testimony of Mr. Bandyk?

Hearing none, the testimony is bound in.

Is there any objection to admitting Exhibits CUB-1 through CUB-10?

Hearing none, those exhibits are

admitted.

(Testimony bound in.)

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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.	U-21534

DIRECT TESTIMONY OF MATTHEW J. BANDYK

ON BEHALF OF

CITIZENS UTILITY BOARD OF MICHIGAN AND MICHIGAN ENVIRONMENTAL COUNCIL

July 26, 2024

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DIRECT TESTIMONY OF MATTHEW BANDYK FOR CUB & MEC
CASE NO. U-21534

I. INTRODUCTION & QUALIFICATIONS

Q. Please state for the record your name, position, and business address.

A. My name is Matthew Bandyk. I am a consultant at 5 Lakes Energy LLC, a Michigan limited liability corporation, located at Suite 218, 220 MAC Avenue, East Lansing, Michigan 48823.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of Citizens Utility Board of Michigan (CUB) and Michigan Environmental Council (MEC).

Q. Please summarize your experience in the field of utility regulation.

A. I have over 14 years of experience in the field of utility regulation as a journalist and financial analyst. My experience is summarized in my resume, provided as Exhibit CUB-1.

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

A. Yes. I have previously testified before the Michigan Public Service Commission (Commission) in the following cases:

Case No. U-21555 (UPPCO Rate case);

Case No. U-21540 (Michigan Gas Utilities Rate case);

Case No. U-21490 (Consumers Energy Gas Rate case);

Case No. U-21389 (Consumers Energy Electric Rate case);

Case No. U-21048 (Consumers Energy 2022 PSCR Plan case); and

Case No. U-21291 (DTE Energy Gas Rate case).

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit CUB-1:	Resume of Matthew J. Bandyk
Exhibit CUB-2:	Total Private Nonfarm Business Multifactor Productivity Index Growth
Exhibit CUB-3:	Annual Percent Change in Michigan Nonfarm Business Labor Productivity Index Growth
Exhibit CUB-4:	"Rate of Return Regulation Revisited," Karl Dunkle Werner and Stephen Jarvis, Energy Institute at Haas
Exhibit CUB-5:	Cost of Capital
Exhibit CUB-6:	Equity Risk Premium and Corresponding Risk-Free Rates
Exhibit CUB-7:	Electric Sample Average Asset Beta Relevered at DTE Electric's Capital Structure with Market Value of Equity
Exhibit CUB-8:	CAPM Analysis
Exhibit CUB-9:	DCF Cost of Equity at DTE Electric's Capital Structure with Market Value of Equity
Exhibit CUB-10:	"The Hamada Beta Adjustment and the Cost of Capital for the Regulated Utilities", IAEE Energy Forum, 2022

II. SUMMARY

Q. What topics are you addressing in your testimony?

A. I am addressing DTE Electric's inflation factor and cost of capital.

Q. Which Company witness's testimony do you discuss in your testimony?

A. I am addressing the testimony of Company witnesses Uzenski and Villadsen.

III. PROJECTED COSTS AND INFLATION FACTOR

Q. How do you view the Company's application of an inflation factor for its historical and projected test year costs?

A. As shown by DTE Electric (hereafter, DTE) Witness Theresa Uzenski in Exhibit A-13, Schedule C5.15, the Company applies non-labor inflation rates of 4.1% and 2.4% for its historical non-labor costs in calendar years 2023 and 2024 and 2.2% for its projected test year costs in calendar year 2025 ("Non-Labor Inflation", row 9). The Company also applied a 3% annual inflation factor to non-contract labor ("Labor Inflation", row 1) and contract labor ("Contractors Inflation", row 5) from 2023 to 2025. While it is prudent to expect that costs will be affected by inflation, it is also prudent to factor in how productivity gains may mitigate inflation. Ms. Uzenski does not make any adjustment for productivity. It is reasonable to expect that a business will, on average, make some productivity gains year to year. That effect can be empirically seen in Bureau of Labor Statistics (BLS) data on total multifactor productivity for the private nonfarm sector, which I have provided in Exhibit CUB-2. As this exhibit shows, the average annual productivity factor change from 2013 to 2023 has been 0.61%. I also obtained BLS data on labor productivity that was

available specifically for Michigan. Exhibit CUB-3 shows the average annual factor change for nonfarm labor productivity in Michigan from 2013 to 2023 is 0.70%.

Q. What is the significance of these productivity factor data?

A. As a regulated utility, DTE does not face the competitive pressures to improve productivity that can be found in non-regulated industries. Therefore, if DTE customers are going to benefit from the cost savings, a productivity factor should be applied to reduce the utility's projected costs when calculating its revenue requirement. Doing so would simulate the effect of productivity improvements on DTE's costs.

The productivity factor data from Exhibits CUB-2 and CUB-3 represent conservative estimates for the basic productivity improvements that have been empirically achieved in the private sector in recent history. I recommend that the Commission apply the Exhibit CUB-2 factor of 0.61% to reduce Non-Labor inflation rates of 4.1%, 2.4% and 2.2% for 2023, 2024 and 2025, respectively. I also recommend the Commission apply the Exhibit CUB-3 factor of 0.70% to reduce the 3% inflation factors for both Labor and Contractors Inflation, for the same years.

IV. <u>COST OF CAPITAL – PRINCIPLES</u>

Q. Please explain the concept of cost of capital and its significance.

A. The cost of capital is the return demanded by investors on the capital they supply to the Company.[1] It is the weighted average of the costs of the various classes of capital supplied by investors — in this case, debt and equity. The cost of debt and cost of equity are each

[1] Roger A, Morin, PhD. Modern Regulatory Finance. PUR Books, 2021, p. 27.

weighted by the respective amounts of debt and equity in the Company's total capital structure, so the ratio of equity to debt is another important component of the cost of capital. The cost of debt can be relatively easily observed through the interest rates lenders demand on debt issued by the Company. The cost of equity, however, is the product of market expectations that can only be estimated by looking at a number of factors.

Estimating the cost of equity for a regulated utility must be done carefully so as to arrive at a return that ensures rates that are "just and reasonable," a principle elaborated on in the landmark U.S. Supreme Court cases that set the legal standards governing public utility regulation, *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia* and *Federal Power Commission v. Hope Natural Gas Co*.

For example, in *Hope*, the Court said that the "just and reasonable" standard implies that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[2]

But the Court was also clear that the determination of what return is "sufficient" in that regard must also involve a consideration of the interests of the company's customers. Indeed, just as a return for a utility that is set below the amount "commensurate with returns on investments in other enterprises having corresponding risks" causes the utility to lose wealth relative to what it should earn with a more appropriate return, a return that is set

[2] *Fed Power Com v Hope Natural Gas Co*, 320 US 591, 603 (1944).

above this amount will cause the utility's customers to be overcharged and lose wealth relative to what they would be charged with a lower and more appropriate return. In this latter case, that wealth is instead transferred from customers to the utility holding company's shareholders.

Q. What methods may be employed to determine the cost of capital?

A. In *Hope*, the Supreme Court held that it is the result reached, not the method employed, which is controlling, and that result should be a rate that people would reasonably consider to be commensurate with the risk of the investment. In practice, reaching that result involves using methods that are widely accepted in the financial community to estimate investor perceptions of risk. I rely on these methods in my testimony to estimate the Company's return on equity (ROE).

Q. How have public regulatory commissions historically fared at estimating returns on equity for utilities that are commensurate with risk?

A. There is strong evidence from multiple observers and peer-reviewed academic research that public regulatory commissions on average have tended to set electric utility ROEs above what objective observers in the financial community would arrive at using the widely-accepted methods for estimating ROE. I will describe this ROE that regulatory commissions have tended to miss as a "market-based ROE" since it is estimated using methods that gauge how the market rates the risk of a utility investment. The failure by commissions to match a market-based ROE has resulted in a transfer of wealth from ratepayers to shareholders.

Arriving at an ROE is a process of estimation, and that process will invariably include some degree of subjectivity. Subjective factors can influence any human decision-making process, including the decisions of public regulatory commissions, and lead to results that vary from objective methods.

Academics have also noted the phenomenon of a growing premium of regulatory commission-awarded ROEs over the rate of return on long-term U.S. Treasury bonds (the risk-free rate), and research has found that this premium cannot statistically be explained by financial fundamentals, such as a change in the equity or debt risk of the utilities in question.[3]

This premium has costs to consumers because it ensures that utilities collect a greater return from consumers than is justified by traditional ROE methodology. A 2023 paper published by the Energy Institute at the University of California Berkeley's Haas School of Business found that the cost to consumers from rates of return for electric and gas utilities that are set above a market-based return reached around $2–20 billion per year by 2020.[4]

[3] "This growing premium does not appear to be explained by traditional asset-pricing models, often in direct contrast to regulators' stated intent… However, absent some normative justification for this premium, it would appear that regulators are authorizing excessive returns on equity to utility investors and that these excess returns translate into tangible profits for utility firms." David Rode and Paul Fischbeck. "Regulated equity returns: A puzzle." Energy Policy, Oct. 2019. Last accessed July 21, 2024, available at https://www.sciencedirect.com/science/article/abs/pii/S0301421519304690?via%3Dihub.

[4] Exhibit CUB-4.

For more evidence of this phenomenon, experts including utility attorney Steve Huntoon have also published evidence indicating that regulators tend to set ROEs above what the market would bear.[5]

A higher return implies higher risk, so the empirical result that awarded ROEs are higher than market returns would imply that regulated utilities are riskier investments than the market as a whole. But they are indeed not riskier. Consider the noncontroversial fact that regulated utility returns tend to be less risky than the market as a whole. This phenomenon can be observed simply by looking at the betas of regulated utility holding companies. Beta is a measurement of the sensitivity of a stock's returns relative to those of the market as a whole. Utility holding company betas tend to be less than one, meaning that those stocks are less sensitive to changes in overall market returns.

Q. If regulated utilities are less risky than the market, then why have regulated utilities historically been awarded ROEs above market returns?

A. The remaining explanation is that public regulatory commissions have tended to accept estimates for ROE that are above fair, market-based ROE estimates. In this case, DTE is proposing an ROE of 10.50%, a significant increase from the 9.9% ROE authorized in its last rate case (U-21297).

Q. Do you agree with this statement from Dr. Villadsen's testimony: "The allowed return on equity needs to be at least as high as the expected return offered by alternative investments of equivalent risk or investors will choose these alternatives instead. If it

[5] Steve Huntoon. "Nice Work If You Can Get It." Fortnightly Magazine, August 2016, last accessed August 29, 2023, available at https://www.fortnightly.com/fortnightly/2016/08/nice-work-if-you-can-get-it.

is not, the utility's ability to raise capital and fund its operations will be negatively impacted."[6]

A. Yes, I do agree. I would add, however, that the corollary is true and important to point out: the allowed return on equity should also be no higher than the expected return offered by alternative investments of equivalent risk or ratepayers will be essentially taxed to provide an excess return to investors. As I discussed above, evidence indicates utility ROEs have been set by regulatory commissions at an excessive premium above a market ROE, suggesting the bigger danger in this proceeding is that the Commission will set the ROE too high, not too low.

Q. Is Dr. Villadsen's recommended ROE of 10.5% a return commensurate with risk in your view?

A. No. As the methodology below shows, Dr. Villadsen's recommended ROE is inflated above what would be a fair return due to several overestimated inputs into her DCF and CAPM analysis as well as her use of a Risk Premium model that essentially recycles the overestimations of ROE by other regulatory commissions.

Q. Would DTE customers pay for an excessive return if the MPSC approves Dr. Villadsen's ROE in this case?

A. Yes. If the MPSC were to accept the utility's request for a rate increase without changes, DTE would collect about $1.31 billion from customers for a return on its rate base, based on an overall rate of return of 5.92% and a total jurisdictional electric rate base of $22.1

[6] Direct Testimony of Dr. Bente Villadsen, p. 10.

billion.[7] If the ROE were instead the market-based ROE of 9.30% that I am recommending in this case, that overall rate of return would fall to 5.45%[8], and so the amount collected would fall from $1.31 billion to $1.20 billion, resulting in savings to customers of about $104 million on an annualized basis.

V. COST OF CAPITAL – METHODS

Q. What quantitative methods did you use to estimate the utility's ROE?

A. As I stated earlier in my testimony, arriving at a ROE commensurate with risk requires the use of the methods that are widely accepted in the financial community to estimate investor perceptions of risk. My ROE estimate is based on the Capital Asset Pricing Model (CAPM) and the Discounted Cash Flow (DCF) methods, which are widely accepted methods for calculating ROE. These are also two of the methods used by Dr. Villadsen to develop her recommended ROE. For reasons I explain below, I did not use either Empirical Capital Asset Pricing Model (ECAPM) or the Risk Premium Model.

Q. Please summarize your ROE recommendation.

A. The results of my DCF and CAPM analyses and my resulting recommendation for the utility's ROE in this case are below:

[7] Exhibit A-14, Schedule D1, p. 1.

[8] Exhibit CUB-5.

CAPM	8.53%[9]
DCF	8.66%[10]
Average of CAPM and DCF	8.59%
DTE ROE awarded in U-21297	9.90%
Recommendation	**9.30%**

Q. Why are you recommending an ROE that is higher than any of the results found in your financial models?

A. The average of my model results suggests that an ROE lower than 9.3% would be a market-based cost of equity for DTE But DTE is not a competitive business solely answerable to market forces, which helps explain why its awarded ROE has historically been significantly higher than the market-based cost of equity.

Any significant changes in DTE's ROE should be implemented gradually so as not to create unnecessary instability in the company's market value, which is based to a great degree on the outcomes of regulatory proceedings like this one.

To account for modeling uncertainty and this principle of gradualism, my final recommendation represents the midpoint between the average result of my models and the 9.9% ROE awarded to UPPCO in its last rate case (U-21297).

[9] Exhibit CUB-8.

[10] Exhibit CUB-9.

Q. Do you agree with Dr. Villadsen's claim that because DTE has higher business risk than the group of comparable companies used in her financial methods, the quantitative estimates for ROE are "conservative"?[11]

A. No. First, it is not clear that the unique risk factors to which she points have any material impact on DTE's risk. Second, those risk factors are mitigated by other factors where DTE is less risky than the group of comparable companies.

Dr. Villadsen points to three factors that she claims elevates DTE's business risk over that of comparable companies: the lack of a revenue decoupling mechanism or lost revenue adjustment mechanism, a heavy reliance on nuclear and coal for generation sources, and a "higher than average need for infrastructure investments."[12]

It is unclear to what extent, if any, these factors materially affect DTE's risk. For example, Villadsen notes that "empirical tests have not been able to detect" the effect of a large reliance on nuclear generation on the cost of capital.[13] She does not identify the precise issue with nuclear power that increases business risk.

In addition, to the extent that any of these factors do have a measurable effect on risk, inputs into market-based cost of equity estimates may already take them into account, meaning the effect on risk is already captured by the results of the quantitative methods. For example, DTE has already announced coal plant retirements to comply with current and anticipated environmental regulations, and so the extent to which coal plant retirements

[11] Villadsen Direct, p. 41.

[12] Villadsen Direct, pp. 6-7, 42-43.

[13] Villadsen Direct, p. 44.

affect DTE's future earnings is already anticipated by the analysts that project those earnings. Those projections are one of the chief inputs for the DCF model.

Second, DTE has less risk than the proxy group in some respects. For example, Dr. Villadsen's Exhibit A-14, Schedule D5.18 identifies that on average, 20% of the proxy group's revenue is from industrial load, compared to 18% for DTE. Industrial load carries more risk than residential or commercial load because it is more concentrated among relatively fewer large customers, making the associated revenue more vulnerable to swings in volatility based on the business decisions of those relatively few customers. For example, one large customer may decide to decrease operations at or shutter a plant, and that decision can have a dramatic impact on electricity sales in a utility's service territory.

In addition, Dr. Villadsen's testimony notes that DTE benefits from some regulatory policies that also apply to "many," but not all, of the proxy group companies. These include a forward test year for rate cases and the ability to include construction work in progress for pollution control measures and "significant new infrastructure projects" in rate base.[14] DTE has less risk due to the decline in regulatory lag for cost approvals from these policies, but not all of the proxy group companies enjoy the benefits of these policies.

Because the effect of the aforementioned risk factors on the DTE's cost of capital is indeterminable, and because other factors decrease business risk relative to the proxy group, I disagree with Dr. Villadsen that business risk should affect the perceived ROE.

[14] Villadsen Direct, p. 41-42.

Q. Please describe your application of the CAPM to estimate the ROE.

A. I provide my CAPM estimate in Exhibit CUB-8.

Dr. Villadsen's use of the CAPM formula is for the most part noncontroversial, and my CAPM analysis follows the same basic formula. The numbers we use for the important inputs to the formula – the equity risk premium (ERP), risk-free rate and beta – differ, for reasons I explain below.

Q. Please explain how you arrived at the ERP used in your CAPM formula.

A. The ERP is an essential component of the CAPM formula. It represents the excess return an investor would receive over the risk-free rate by investing in the broader equity market. The ERP is calculated as the estimated return on the market an investor can expect from investing in the broad stock market minus the risk-free rate.

Dr. Villadsen's CAPM estimate for ROE is inflated by her choice of ERP for her Scenario 1 CAPM analysis. This 7.17% ERP is the historical average premium of market returns over the income returns on government bonds from 1926 to 2022.[15]

Historical estimates like this one have a flawed methodology that leads to an inaccurate estimate of market return. While historical estimates of ERP are indeed commonly used by the financial community, that popularity does not make them less flawed. As New York University Stern School of Business Professor Aswath Damodaran has written:

[15] Villadsen Direct, p. 23.

> *Given how widely the historical risk premium approach is used, it is surprising how flawed it is and how little attention these flaws have received.*[16]

There are two main reasons for the flaw with this methodology. First, the historical estimate for ERP is extremely sensitive to the historical time period selected, meaning that the subjective judgment by the person making the estimate of which time period to collect market data for has an outsized impact on the ultimate result. To apply that issue to Dr. Villadsen's argument, the timeframe for her estimate from 1926 to 2022 produces a different result than if the timeframe was some other subset of that nearly 100-year period.

Second, regardless of the time period selected, historical estimates of ERP are subject to the problem of survivorship bias, where returns that go into historical ERPs tend to be those from stocks that remain in the market, rather than those that drop out. This survivorship bias effect tends to inflate historical ERPs.

Q. Are there any methods of estimating ERP not subject to these problems?

A. Yes. Dr. Damodaran suggests using an "implied equity risk premium" method:

> *The advantage of this approach is that it is market-driven and current, and does not require any historical data. Thus, it can be used to estimate implied equity premiums in any market.*[17]

This approach values stocks in a market at the present value of dividends from each stock growing at a constant rate.

[16] Aswath Damodaran, "Estimating Equity Risk Premiums," Stern School of Business, at p. 10, accessed July 21, 2024, available at https://pages.stern.nyu.edu/~adamodar/pdfiles/papers/riskprem.pdf.

[17] *Id.* at p. 20.

Dr. Damodaran regularly publishes an estimate of the U.S. ERP based on this implied equity premium approach. The ERP I used in my estimate is an average of this estimate from Dr. Damodaran and ERP estimates from two other sources: First, the average U.S. market risk premium identified by the 2023 IESE Business School survey of thousands of finance and economics professors, analysts, and managers of companies. While described as a "market risk premium," this number indicates the equity risk premium for the U.S. market. Second, I used the recommended U.S. ERP from financial research firm Kroll for 2023. Kroll's recommended U.S. ERP is based on risk perceptions in the market and other qualitative and quantitative inputs, such as an implied equity risk premium model. I have provided the sources and my calculation of equity risk premium from these estimates in Exhibit CUB-6.

Q. Why did you use the average of multiple ERPs, instead of just one, such as the Bloomberg estimate used by Dr. Villadsen in her Scenario 2 CAPM analysis?[18]

A. The use of multiple different sources mitigates the risk of error from any one source. Mitigating this risk is especially important when dealing with projections, since the future is inherently uncertain, making any one source for an ERP subject to forecasting error. This risk cannot be eliminated but can be significantly reduced by consulting multiple sources each with their own methodologies for estimating ERP.

[18] Exhibit A-14, Schedule D5.11, p. 2.

Q. Dr. Villadsen claims that the 7.17% historic risk premium is "more reasonable" than the forward-looking Bloomberg estimate of 6.37%.[19] Do you agree?

A. No. In addition to the methodological problems with the historic risk premium that I explained above, I also see problems with her claim that the 7.17% is more reasonable because it is closer to the 7.87% and 7.90% risk premiums she calculates in her Exhibit A-14, Schedule D5.17. Those risk premiums are much higher than the risk premiums from Exhibit CUB-6 that all come from widely-used, highly reputable sources that lack the methodological problems that come with extrapolating a forward ERP from historic data. Therefore, I discount her risk premiums from Exhibit A-14, Schedule D5.17 because they are so much higher than these other sources.

Q. Why did you not use the ECAPM?

A. It is not a widely accepted method as part of ROE analyses in rate cases.[20][21]

Q. For the beta in the CAPM formula, Dr. Villadsen adjusts the betas from the proxy group companies to remove the effect of the differing amounts of leverage of the companies, and then ultimately uses a beta in the formula that is relevered at DTE's debt-equity ratio. How do you evaluate this adjustment?

A. I agree with Dr. Villadsen on the need to adjust beta to reflect that a higher level of debt within a company's capital structure increases the risk of equity, and thus the average of

[19] Villadsen Direct, Appendix B, p. 7.

[20] See, e.g., Case No. U-21389, PFD, pp. 337-38.

[21] "This PFD notes that Consumers has not identified an order wherein the Commission has recognized let alone adopted the use of the ECAPM model, and this ALJ is unaware of any." Available at: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000BCjcrAAD.

the proxy group betas cannot be representative of the beta for DTE until the average has been recalculated to remove the effect of debt. Dr. Villadsen is correct when she states that the unadjusted beta is "the one observed in market data as a consequence of the firm's actual market value capital structure"[22] and that once unlevered, the resulting adjusted betas for the proxy companies "are comparable on an 'apples to apples' basis, since they reflect the systematic risk inherent in the assets of the proxy companies, independent of their financing."[23] To perform this unlevering, she uses a debt-equity ratio in which the equity is the market value of equity, as calculated by multiplying the number of common shares outstanding by the price of common shares. This market capitalization figure is used as the equity value for each company as opposed to the book value of equity when adjusting beta.[24] The book value of equity diverges from the market value, meaning using one versus the other in the beta adjustment formula will change the result, so it is important to consider which equity value is proper to use. The market value of equity is theoretically consistent with the Hamada adjustment because the risk of equity is based on investor perceptions in the market. The book value of equity is therefore less theoretically consistent because it is based on accounting principles and not investor perceptions. For debt, the market value and book value of debt are typically identical because they are both based on yields of issued bonds as actually observed in the market.

Dr. Villadsen properly uses the market value of equity when unlevering the proxy company betas to arrive at asset betas. But when relevering the average asset beta of the proxy group,

[22] Villadsen Direct, Appendix B, p. 14.

[23] Villadsen Direct, Appendix B, p. 15.

[24] Exhibit A-14, Schedule D5.3.

she uses DTE's book value equity. The result is a beta that is not only inconsistent with the Hamada adjustment theory and unable to be interpreted as a representation of the company's risk vis-à-vis the market,[25] but also is inflated compared to what the beta would be if the market value of equity was used in the adjustment.

That inflation materially and improperly increases the cost of equity calculated by the CAPM formula. I correct Dr. Villadsen's Hamada adjustment in Exhibit CUB-7. Because DTE Electric is not a publicly traded company, I cannot use market capitalization to identify the market value of its equity. Instead, I looked to the 5-year average market common equity to market value ratio for the proxy group of 58%[26] and used that as a proxy for DTE's equity market value. Using a debt-equity ratio of 42%/58% in the Hamada adjustment results in a beta of 0.93, noticeably lower than the beta of 1.04 that Dr. Villadsen calculates using a 50%/50% debt-equity ratio based on the book value of DTE equity.

Q. Please explain your application of the Discounted Cash Flow (DCF) model to estimate the Company's cost of equity.

A: For the most part, my DCF model follows the same formula as Panel B of Dr. Villadsen's DCF analysis, which uses a multi-stage approach with a perpetual growth rate of 3.9%, matching the forecasted long-term nominal U.S. GDP growth rate. Where we differ regarding the multi-stage model is the adjustment she makes to the results of her model to

[25] "…relevering the market value unlevered beta using the book value debt/equity ratio, yields a beta estimate that cannot be interpreted, and therefore cannot legitimately be used in the estimation of the cost of capital in the CAPM model." Linn and Zhu, "The Hamada Beta Adjustment and the Cost of Capital for the Regulated Utilities," IAEE Energy Forum, Third Quarter 2022. See Exhibit CUB-10.

[26] Exhibit A-14, Schedule D5.11.

account for the differing amounts of debt in the capital structures of the proxy group companies. After computing the average after-tax cost of capital for her proxy group, Dr. Villadsen calculates the cost of equity portion of that cost of capital using DTE's capital structure. But like with the Hamada adjustment to beta in CAPM, Dr. Villadsen uses the book value of equity from DTE's capital structure.[27] Once again, this choice of equity value leads to an inflated result because of the difference between book value equity and market value equity. When computing the after-tax cost of capital, Dr. Villadsen uses market value equity, which is the approach consistent with finance theory because, as with the Hamada adjustment to beta, the cost of equity that makes up the cost of capital that we are after is based on investor perceptions of risk, not a book value that is a product of accounting rather than market perceptions.[28] In Exhibit CUB-9, I recalculate the cost of equity for the DCF model using the market value for equity.

Q. Why did you disregard Panel A of Dr. Villadsen's DCF analysis?

Dr. Villadsen's simple DCF model lacks a long-term growth rate and relies only on a short-term growth rate. As I will explain, valuing a company's equity without a realistic assumption about its long-term growth leads to an essentially meaningless outcome.

[27] Exhibit A-14, Schedule D5.8.

[28] Exhibit A-14, Schedule D5.7.

Dr. Villadsen's "long-term combined growth rate" [29] is not truly a long-term rate in the sense of what is demanded by the DCF model because it is based on a combination of 3 to 5 year earnings growth rates projected by Thomson Reuters IBES and Value Line.[30]

When a DCF model uses a growth rate of no more than five years as its only growth rate, the model's outcome is wildly unrealistic. If the growth rate used in the DCF model is higher than that of the growth rate of the economy as a whole, that implies that in the long run, the Company would grow bigger than the entire U.S. economy. Such an outcome is theoretically impossible, as Dr. Damodaran has explained:

> *If a firm is a purely domestic company, either because of internal constraints . . . or external constraints (such as those imposed by a government), the growth rate in the domestic economy will be the limiting value.* [31]

Q. Do you agree with Dr. Villadsen's statement that the results of her multi-stage DCF model used in Panel B, which does use a perpetual growth rate, are "unrepresentative"[32] compared to the results of her simple DCF model used in Panel A, which does not use a perpetual growth rate?

A. No. The simple DCF model should not be considered toward the utility's ROE. Dr. Villadsen's reasons for preferring the simple DCF model to the multi-stage model is that the multi-stage model results "are out of line with other results" and that they "may fail to

[29] Exhibit A-14, Schedule D5.6.

[30] Exhibit A-14, Schedule D5.5.

[31] Aswath Damodaran. *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset*, 3rd ed. John Wiley & Sons, Inc, 2012.

[32] Villadsen, p. 38, 9.

capture the substantial growth needed in the electric sector to accomplish the transition to low-carbon economy, which may require a higher growth for a prolonged period of time."[33]

Regarding the first reason, the fact that the multi-stage model results are lower than her other cost of equity estimates is no reason to reject it. It may reflect that her other estimates are too high, not that the multi-stage model estimate is too low. As noted above, her simple DCF and CAPM model results are inflated, and I will explain why her other estimate, which uses the Risk Premium model, is inflated as well.

Regarding the second reason, Dr. Villadsen does not explain what level of growth is needed for this low-carbon transition, and why the multi-stage model results would fall short.

Q. Why did you not use the Risk Premium method used by Dr. Villadsen as one method to estimate ROE?

A. Dr. Villadsen's Risk Premium analysis should be disregarded because it introduces into the calculation of ROE, a process that should be based on objective data as much as possible, the reliance on ROEs set by other regulatory commissions. That regulatory process of setting ROE is, as the research about excessive utility ROEs I discussed above supports, not one that has empirically resulted in returns that would be set by objective financial methodology.

Her risk premium is the spread between those ROEs historically set by other commissions in rate cases and the 20-year Treasury bond yield.[34] Therefore, the resulting risk premium

[33] Villadsen Direct, p. 38.

[34] Villadsen, p. 39, 5-6.

she calculates is as large as it is only in relation to the degree that regulatory commissions set ROEs at a premium to what the ROEs would be using only objective financial methods.

This problem with the Risk Premium model has been cited by FERC as one of the reasons to reject the use of the model. In Opinion No. 569 in a 2019 order, FERC found that "while all models, including the DCF, feature some circularity, such circularity is particularly direct and acute with the Risk Premium model because it directly relies on past Commission ROE decisions."[35] In that decision, FERC also rejected the use of the Risk Premium model because it is "largely redundant with the CAPM."[36]

Because academic research has shown the reliance on historic allowed returns to be distorted from objective methods to determine a reasonable rate, the Commission should disregard the proffered Risk Premium approach.

VI. RECOMMENDATIONS

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

A. On behalf of CUB, I recommend that the Commission:

(1) Reduce the inflation factor by my recommended 0.61% productivity factor for non-labor inflation and 0.70% productivity factor for labor inflation; and

(2) Approve an ROE of 9.3%.

[35] FERC Opinion 569, 169 FERC 61129 (2019), par. 343. Available at: https://www.ferc.gov/sites/default/files/2020-04/E-11_1.pdf.

[36] FERC Opinion 569, par. 341.

My silence regarding any position taken by the Company in its application or direct testimony in this proceeding does not indicate CUB's endorsement of that position.

Q. Does that complete your testimony?

A. Yes.

MS. ANDREWS: Thank you, your Honor. Next, I would move for the admission into the record of the Revised Direct Testimony of Joshua Denzler on behalf of the Citizens Utility Board of Michigan, the Michigan Environmental Council, and the Natural Resources Defense Council. Mr. Denzler's revised direct testimony consists of a cover page, table of contents, and 14 pages of question and answers. And I would also move for admission Exhibits CUB-11 through CUB-16 that were sponsored by Mr. Denzler. I would note that Mr. Denzler also has a confidential version of his testimony, which I would move to be bound into the confidential transcript, and he has a confidential version of Exhibit CUB-14, which I would also move to be bound into the confidential record in this case.

JUDGE WALLACE: Thank you, Ms. Andrews. Is there any objection to binding in the revised direct testimony of Mr. Denzler into both the Public and a Confidential Record?

Hearing none, the testimony is bound in.

Is there any objection to the admission of Exhibits CUB-11 through CUB-16; CUB-14 has a confidential version?

Hearing none, those exhibits are admitted.

(Public Testimony Bound Into the Public Record.)

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(Confidential testimony found on Page 5247 of the Confidential Record.)

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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.	U-21534

PUBLIC VERSION

REVISED DIRECT TESTIMONY OF JOSHUA W. DENZLER

ON BEHALF OF

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

August 23, 2024

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I. INTRODUCTION & QUALIFICATIONS

Q. Please state for the record your name, position, and business address.

A. My name is Joshua W. Denzler. I am a Consultant at 5 Lakes Energy, a Michigan limited liability corporation, located at Suite 218, 220 MAC Avenue, East Lansing, Michigan 48823.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of Citizens Utility Board of Michigan (CUB), Michigan Environmental Council (MEC), Natural Resources Defense Council (NRDC).

Q. Please summarize your experience in the field of utility regulation.

A. My work experience is summarized in my resume, provided as Exhibit CUB-11. I have been in the utility industry since the summer of 2014, where I started my career at DTE Energy as a Summer Student (intern) working in continuous improvement for DTE Gas. After completing a second summer internship on the same team in the summer of 2015, I became a student co-op in Gas Construction and Planning.

I began my full-time career in 2017 when I became an Apprentice Planner in Electric Distribution Operations New Business Service Planning. In 2019, I became a Strategist in the Regional Customer Operations division of Electric Distribution Operations. I was promoted to Senior Strategist in this same organization in 2021. In late 2022, I became a Senior Strategist in Corporate Strategy supporting the Next Generation Utility effort before departing the company in early 2023. From that time until May 2024, I was employed by E Source Companies, LLC, as a Director of Sales Innovation responsible for marketing

advanced data science tools within the utility industry. I have been employed by 5 Lakes Energy since May 2024.

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

A. I have not previously testified before the Michigan Public Service Commission or in any other similar proceeding.

Q. What is the purpose of your testimony?

A. I am testifying on behalf of MNSC regarding the following topics:

1. The proposed Storm Recovery Cost Sharing Mechanism;
2. The Company's vegetation management risk prioritization model;
3. The proposed changes to Contribution in Aid of Construction (CIAC);
4. The Company's staffing baseline assumptions, particularly after their Voluntary Separation Incentive Package; and

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit CUB-11: Resume of Joshua W Denzler

Exhibit CUB-12: Case No. U-12270, June 14, 2024, DTE Electric Annual Report.

Exhibit CUB-13: Discovery Response MNSCDE-13.27

Exhibit CUB-14: Discovery Response MNSCDE-13.2b + *Confidential attachment* NDA_U-21534 MNSCDE-13.2b Preliminary Estimated Net VSIP O&M Savings

II. REQUESTED STORM RESTORATION COST SHARING MECHANISM

Q. Please summarize the Company's proposal for a Storm Restoration Cost Sharing Mechanism (SRCSM).

A. The Company is proposing that the current methodology for calculating projected storm restoration O&M costs remain consistent. However, the Company is proposing that, at the end of each year, the differences in actual incurred Storm costs versus projected costs, whether over or under the projection, would be split 50/50 between the Company and customers via regulatory asset or liability.[1]

Q. Is the Company's proposed SRCSM good for customers?

A. In general, no it is not. The proposal is likely to unduly skew the cost of Storms against customers and in favor to the Company and its shareholders. There are two main drivers of this imbalance inherent to the Company's proposal:

1. It skews the share of risk significantly in favor of the Company, at the expense of ratepayers.
2. It creates a strong misalignment of incentives, when the Company's historical storm performance is already very poor.

Q. How does the Company's proposed SCRSM create an imbalance of risk for customers?

A. The Company's proposal would reduce far more risk for the Company than it would for customers. If the increased storm severity projected by the Company are realized, it is much

[1] Revised Direct Testimony of Witness Foley, p. NTF-68.

more likely for costs to exceed projections than to be under projections. This means that cost collections from customers will be more likely than refunds to customers, resulting in a greater risk reduction for the Company than for customers.

Q. How has the Company's storm performance been in recent years?

A. The Company's overall storm performance can only be described as poor. Some of the most telling evidence of this comes from their SAIDI and SAIFI performance both in all-weather and excluding-Major Event Days (MED) conditions. The Company's all-weather SAIDI performance has been in the bottom quartile every year between 2017 and 2022, except for 2020. SAIDI Excluding MEDs has been mildly better comparatively, with 2020-2022 in third quartile while 2017-2019 is still in fourth quartile. A similar trend can be seen in the Company's SAIFI performance, where the Company generally ranks in lower quartiles for all-weather SAIFI as opposed to excluding-MED conditions.[2] For the Company's customers, this means that, while their overall reliability performance is rather poor when compared to other utilities, the Company's Storm performance is exceptionally poor in comparison to other utilities.

Further evidence to support the Company's poor Storm performance is found in the MPSC Service Quality and Reliability Standards for Electric Utilities Report Rule 460.731 for 2023.[3] This report shows that Company Storm response did not comply with the MPSC Annual Performance standards for Outage Restoration in All Conditions, Gray-Sky Conditions, and Catastrophic Conditions, among others.

[2] Direct Testimony of Kryscynski, pp. AJK-19-21, Figures 2-5.

[3] Ex CUB-12, Case No. U-12270, June 14, 2024, DTE Electric Annual Report.

As evidenced by both of these data sets, despite millions of dollars of investment, the Company's customers are receiving unduly long and more frequent outages during Storm events.

In addition to the Company's woeful underperformance in restoring Storm outages, their performance in communicating accurate restoration is also lacking. The Company stated that from 2018-2022, they did not even measure estimate accuracy outside of Blue-Sky days.[4] This shows a historic and systemic disregard for the impact of Storms and importance of accurate and timely communications with customers experiencing outages.

Continuing with this disregard is the fact that the Company only provides an estimated *day* of restoration during Storm events.[5] The wide potential for actual restoration across an entire day's time could make the difference on whether a customer will be able to work from home, if their food will spoil, and potentially even if they experience a medical emergency. Such a vague estimate leaves customers in a difficult position to properly respond to being without power.

While the broadness of these restoration estimates alone is far less than ratepayers deserve, the Company still underperforms in achieving them. The Company's Catastrophic Storm First Estimate accuracy was 46% in 2023 and the Non-Catastrophic Storm First Estimate accuracy was 60% in 2023.[6] The 2024 June YTD estimate accuracies are higher (70% for

[4] ExCUB-13, Discovery Response MNSCDE-13.27b.

[5] Ex CUB-13, Discovery Response MNSCDE-13.27a.

[6] Ex CUB-13, Discovery Response MNSCDE-13.27bi.

Catastrophic and 55% for non-catastrophic) but still represent a significant gap in the Company's service and communication to its customers.[7]

When the Company underperforms in restoring customers impacted by a Storm, those customers should at least have accurate information to respond accordingly to the overly frequent and unnecessarily long outages endure.

Q. Will the new proposal incentivize improvement in Storm spending and performance?

A. No, it will not. The Company states that the cost sharing proposal means the Company is "incentivized to control costs because it must absorb 50 cents of every incremental dollar that is spent."[8] If this were the case, the Company would be more incentivized to control costs if it had to absorb 100% of every incremental dollar that is spent. At bottom, the Company's proposal would mean that every incremental restoration dollar spent now would cost the Company only $0.50, when that dollar falls into the Storm category. This would create a financial incentive for the Company to extend the duration of Storms and perform additional work under the Storm umbrella as it would be 50% cheaper than if performed after Storm-close. Additionally, the Company has stated there is no current standard, other than field crew judgement, on when to repair versus replace field assets, and has not conducted a cost/benefit analysis to support any such decisions.[9] Particularly

[7] *Id.*

[8] Foley Revised Direct, p. NTF-71.

[9] Discovery Request MNSCDE-13.26a ("Refer to Hill p. BLH-17. Witness Hill discusses the downsides of deferring emergent replacement work. a. Please provide the company's processes and decision criteria for making decisions of repairing vs. replacing work and how it considered cost/benefit in developing these criteria. Answer: Field crews decide whether to repair or replace equipment based off their experience and judgment. For example, if a crew finds a broken wooden crossarm, they would not repair it but replace it

with the absence of any objective standard, the Company may alter Storm decision making to take advantage of this new cost share structure. Further misalignment of incentives would be driven by the fact that failure to keep storm restoration costs down would increase the size of the five-year trailing average storm cost projection that customers must pay. It is clear that the Company's proposal is not in the interest of ratepayers.

Q. If the Company's proposal is rejected, does that mean the Company has no other means to address the volatility from severe weather events?

A. Not, it does not. The Commission offers DTE an opportunity to earn a return on investment to compensate shareholders for risk. Earnings volatility, including earnings volatility due to storm cost recovery, is one of the risks the rate of return is intended to cover. From this perspective, DTE is already being compensated for storm recovery cost risk.

Q. What is your recommendation to address Storm cost recovery?

A. In light of the imbalance to the share of risk, the Company's poor Storm performance, and the likelihood for misaligned incentives, I recommend that the Commission reject the Company's SCRSM proposal. The Company's financial recovery from Storm should be tied to a balanced set of relevant performance metrics to ensure an alignment of incentives to the public interest. I recommend the Commission order DTE to develop Storm performance criteria that include outage restoration, estimate accuracy, resource productivity, and financial responsibility specific to Storm scenarios and tie-bar financial recovery of excess Storm restoration costs to the Company's performance in these areas.

with a fiberglass crossarm. The Company has not done a formal cost/benefit analysis in determining these criteria.").

This would create an incentive for innovation and improvement so that customers receive the Storm restoration outcomes they deserve.

In light of the fact that the Company effectively receives compensation for weather volatility, should the Commission approve the Company's storm recovery cost sharing proposal despite my recommendation, I recommend the Commission reduce the rate of return it authorizes on these costs.

III. TREE TRIM RISK PRIORITIZATION MODEL

Q. How did the Company develop its Tree Trim risk prioritization model?

A. The Company implemented a risk prioritization model that leverages remote sensing data, advanced analytics, and machine learning to determine optimal trim cycles for their vegetation management work. This work was done with a combination of internal Company IT resources and an external consultant.[10]

Q. What should a risk prioritization model do?

A. There are two key objectives of a risk prioritization model when it comes to any utility program, including tree trim/vegetation management. The first objective is to accurately quantify the vegetation-related risk on a portion of the electric grid. The basic question it should answer is: "what is the risk of a tree related outage on this part of the grid, and how does it compare to the rest of the grid?" Ideally, this should be able to be done at sub-circuit resolutions, but at the very least it should be done at the circuit-level. Additionally, the risk

[10] Direct Testimony of Rachel C. Steudle, p. RCS-31.

of an outage should ideally be considered in conjunction with the expected customers impacted and the expected duration of the outage.

The second objective of the tool should be to accurately estimate the cost to mitigate the tree risk it identifies. This expected cost would likely be derived from expected labor hours and equipment needs based on the model's analysis of the necessary tree trim work. The purpose of this second objective is that it allows the utility to optimize its tree spend. A strong tree risk prioritization model will help the Company to estimate its cost per expected unit of reliability (i.e. SAIFI/SAIDI/CAIDI) avoided.

Q. How can the Company know if its risk prioritization model is effective?

A. When evaluating a vegetation management data modeling tool, utilities typically have two options: build the tool internally or purchase from an external vendor. While the Company did choose to build the tool internally, there exist many vendors in this space, from smaller start-ups to large and established corporate enterprises. A sample of key players includes: AIDash, Overstory, E Source, Hitachi, IBM, GE, Trimble, Leidos, and others.

In order to effectively evaluate the benefits of its risk prioritization model, the Company should evaluate its cost/benefit over time. The cost includes the cost to produce and maintain the model, but also the opportunity cost of what other models, internally or externally constructed, can be expected to do. The benefit can be measured by actual (for completed work) and projected expected (for future work) units of reliability avoided per dollars spent. This should be benchmarked against not only the Company's own baseline (i.e. what results they would see if they still used their previous planning methods) but

against the results seen by other utilities, both those with internally- and externally-constructed models.

Q. What is your recommendation as it relates to the tree trim risk prioritization model?

A. As this model is a new creation and previously untested, it is incredibly important to monitor its performance over time and ensure that tree trim resources are being deployed at absolute optimum. I recommend the Commission order an annual audit and evaluation into the Tree Trim planning and decision-making process, including the value of the risk prioritization model. As noted above, this evaluation should compare the Company's results to its previous baseline and the results seen by other utilities.

IV. PROPOSED CHANGES TO CONTRIBUTION IN AID OF CONSTRUCTION

Q. What are the Company's proposed changes for Contribution in Aid of Construction (CIAC)?

A. The Company is proposing substantial increases for thirteen different CIAC rate items. These increases are substantial with factors range from 2.4x - 6.1x the previous CIAC rate.[11]

The Company is taking a step forward by updating its CIAC rates – one that is long overdue as evidenced by the substantial amounts of proposed change. It is incredibly important that the Company ensure that CIAC stays accurate and relevant, so that new business customers pay their fair share of new business costs.

[11] Direct Testimony of Witness Brian L. Hill, pp. BLH-30-31, Table 5.

Q. What are your recommendations?

A. To ensure that implemented CIAC accurately reflects the current costs of construction and desired contributions, I recommend the Commission order a report in the next rate case proceeding detailing the impact of the CIAC changes. This should include a review of the new business construction costs and CIAC received, with comparison to historic and projections of future new business construction costs and CIAC received.

Additionally, the Commission should ensure that CIAC sees regular updates in the future so that it does not drift so far from actual costs again. To this end, I recommend the Commission order a regular review of CIAC costs. I recommend a review cadence of at least once every two years, but certainly no longer than once every five years.

V. COMPANY STAFFING BASELINE IN THE INSTANT CASE

Q. Please summarize the Company's Voluntary Separation Incentive Program.

A. On January 8, 2024, the Company offered a "Voluntary Separation Incentive Package (VSIP)" to 1,025 of its employees and 1,622 DTE Energy Corporate Services LLC employees.[12] This VSIP could otherwise be referred to or classified as a buyout. In discovery, the Company indicated 140 DTE Electric employees and 249 DTE Energy

[12] DTE Response to AGDE-1.23a ("A voluntary separation incentive package (VSIP) was offered to 1,025 DTE Electric employees and 1,622 DTE Energy Corporate Services, LLC employees (shared service employees) on January 8, 2024.").

Corporate Services, LLC employees accepted the VSIP, with projected costs of $30.6 million in 2024 and estimated savings of up to $20.2 million may materialize in 2025.[13]

Q. How is the Company treating the reduction in headcount post-VSIP in the instant case?

A. The Company has stated that any future savings are not embedded in the instant case and will instead be embedded into future rate cases.[14] In discovery response to MNSC, DTE provided an overview of the VSIP, which indicates [[ ]][15] DTE estimates the total projected savings of $20.2M in O&M savings in 2025.[16] This is subject to change based on potential future

[13] DTE Response to AGDE-1.23c ("140 DTE Electric employees and 249 DTE Energy Corporate Services, LLC employees accepted the VSIP. The package was not offered in 2023. There are no projected savings for 2024 due to DTE Electric's actual costs of the program (the accrued separation payments) of $30.6 million. A primary purpose of the VSIP was to realign the workforce to support the changing nature of the Company's work and how we do it, such as an increased focus on infrastructure investments, cybersecurity, and the clean energy transition.

Because of this, DTE Electric is still evaluating potential 2025 cost reductions due to the need to fill key roles so that we can continue our progress towards building more modern infrastructure and a future with lower carbon emissions. Currently, DTE Electric estimates that up to $20.2 million in expense reductions could materialize in 2025, inclusive of both labor and employee benefits. This estimate will continue to evolve due to the need to fill many key roles. This savings estimate also does not include any offset of the program costs. If actual savings are realized in 2025, they will be embedded in the Company's rates as actual costs in a future rate case.").

[14] Discovery Response AGDE-1.23c.

[15] Ex CUB-14C, Response to MNSCDE-13.2b, *Confidential Attachment* NDA_U-21534 MNSCDE-13.2b Preliminary Estimated Net VSIP O&M Savings.

[16] Ex CUB-14, Response to MNSCDE-13.2b; see also Discovery Response AGDE-1.23c.

hiring needs and does not include any costs associated with the program, which total $30.6M.[17]

Q. Is it reasonable for the Company to use pre-VSIP staffing levels as its baseline for cost recovery?

A. No, it is not. This is analogous to selling your home in June to move in rent-free with a relative, but still trying to deduct the mortgage interest for the whole year on your tax return. It does not make sense that the Company would include costs for employees that are no longer there. Since the Company elected to offer a buyout, it is reasonable to expect that staffing levels after that buyout should become the new budgetary norm. The Company should have to justify the expense of additional headcount above the VSIP-departures, not automatically receive those funds and then justify it down later.

Q. Why is it unreasonable for the Company to include backfilled positions in the instant case?

A. Essentially, the Company is asking the rate payers to bear the risk for the volatility of its staffing levels. The Company elected to do the buyout in 2024, and also chose to use 2025 as their projected test year, while still in the midst of significant staffing fluctuations. The Company has not properly justified its staffing baseline for 2025, as evidenced in their Discovery response to MNSC, where they stated "This estimate will continue to evolve..."[13]

[17] *Id.*

Q. What are your recommendations?

A. I recommend that the Commission establish the post-VSIP staffing cost as the baseline for the instant case for 2025 Total O&M Expense in Exhibit A-13 Schedule C5 based on VSIP departures to date, irrespective of any backfilling.

VI. RECOMMENDATIONS

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

A. On behalf of MNSC, I recommend that the Commission:

(1) Reject the Company's proposed Storm Restoration Cost Sharing Mechanism.

(2) Order the Company to develop a proposal to tie financial recovery from excess Storm spending to a balanced set of relevant performance metrics to ensure an alignment of incentives, using Storm performance criteria that include outage restoration, estimate accuracy, resource productivity, and financial responsibility specific to Storm scenarios.

(3) Order DTE to evaluate on an annual basis the Tree Trim planning and prioritization process, including the risk prioritization model, to ensure optimized deployment of those resources.

(4) Establish regular CIAC updates as a mandatory item in future rates.

(5) Establish the post-VSIP staffing costs as the baseline for the instant case, exclusive of any planned or completed backfills.

Q. Does that complete your testimony?

A. Yes.

MS. ANDREWS: Thank you, your Honor. Next, on behalf of the Citizens Utility Board of Michigan, the Sierra Club, the Michigan Environmental Council, and the Natural Resources Defense Council, I move for the admission of the Revised Direct Testimony of Douglas Jester, which consists of a cover page, table of contents, 34 pages of questions and answers, and also for the admission of Exhibits CUB-17 through CUB-19, and I would note that there is both a public and confidential version of the revised testimony of Mr. Jester, and I would move for the confidential version to be bound into the confidential transcript in this case.

JUDGE WALLACE: Thank you. Is there any objection to binding in the revised direct testimony, both public and confidential versions, of Mr. Jester?

Hearing none, the testimony is bound in.

Is there any objection to the admission of Exhibit CUB-17 through CUB-19?

Hearing none, those exhibits are admitted.

(Public testimony bound in. Revisions in the public testimony eliminated the need for a confidential version.)

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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.	U-21534

PUBLIC VERSION

REVISED DIRECT TESTIMONY OF DOUGLAS B. JESTER

ON BEHALF OF

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

August 23, 2024

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REVISED DIRECT TESTIMONY OF DOUGLAS B. JESTER FOR MNSC
CASE NO. U-21534

I. INTRODUCTION & QUALIFICATIONS

Q. Please state for the record your name, position, and business address.

A. My name is Douglas B. Jester. I am Managing Partner of 5 Lakes Energy, a Michigan limited liability corporation, located at Suite 218, 220 MAC Avenue, East Lansing, Michigan 48823.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of Citizens Utility Board of Michigan (CUB), Sierra Club (SC), Michigan environmental Council (MEC), and Natural Resources Defense Council (NRDC).

Q. Please summarize your experience in the field of utility regulation.

A. I have worked for more than 30 years in utility industry regulation and related fields. My work experience is summarized in my resume, provided as Exhibit CUB-17.

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

A. I have previously testified before the Michigan Public Service Commission ("Commission") in the following cases:

- Case U-17473 (Consumers Energy Company Plant Retirement Securitization);
- Case U-17096-R (Indiana Michigan 2013 PSCR Reconciliation);
- Case U-17301 (Consumers Energy Renewable Energy Plan 2013 Biennial Review);
- Case U-17302 (DTE Energy Renewable Energy Plan 2013 Biennial Review);
- Case U-17317 (Consumers Energy 2014 PSCR Plan);
- Case U-17319 (DTE Electric 2014 PSCR Plan);

- Case U-17671-R (UPPCO 2015 PSCR Reconciliation);
- Case U-17674 (WEPCO 2015 PSCR Plan);
- Case U-17674-R (WEPCO 2015 PSCR Reconciliation);
- Case U-17679 (Indiana-Michigan 2015 PSCR Plan);
- Case U-17688 (Consumers Energy Cost of Service and Rate Design);
- Case U-17689 (DTE Electric Cost of Service and Rate Design);
- Case U-17698 (Indiana-Michigan Cost of Service and Rate Design);
- Case U-17735 (Consumers Energy General Rates);
- Case U-17752 (Consumers Energy Community Solar);
- Case U-17762 (DTE Electric Energy Optimization Plan);
- Case U-17767 (DTE General Rates);
- Case U-17792 (Consumers Energy Renewable Energy Plan Revision);
- Case U-17895 (UPPCO General Rates);
- Case U-17911 (UPPCO 2016 PSCR Plan);
- Case U-17911-R (UPPCO 2016 PSCR Reconciliation);
- Case U-17990 (Consumers Energy General Rates);
- Case U-18014 (DTE General Rates);
- Case U-18089 (Alpena Power PURPA Avoided Costs);
- Case U-18090 (Consumers Energy PURPA Avoided Costs);
- Case U-17911-R (UPPCO 2016 PSCR Reconciliation);
- Case U-18091 (DTE PURPA Avoided Costs);
- Case U-18092 (Indiana Michigan Power Company PURPA Avoided Costs);
- Case U-18093 (Northern States Power PURPA Avoided Costs);

- Case U-18094 (Upper Peninsula Power Company PURPA Avoided Costs);
- Case U-18095 (Wisconsin Public Service Company PURPA Avoided Costs);
- Case U-18096 (Wisconsin Electric Power Company PURPA Avoided Costs);
- Case U-18224 (UMERC Certificate of Necessity);
- Case U-18232 (DTE Renewable Energy Plan);
- Case U-18255 (DTE Electric General Rates);
- Case U-18322 (Consumers Energy General Rates);
- Case U-18406 (UPPCO 2018 PSCR Plan);
- Case U-18408 (UMERC 2018 PSCR Plan);
- Case U-18419 (DTE Certificate of Necessity);
- Case U-20072 UPPCO 2017 PSCR Reconciliation);
- Case U-20111 (UPPCO Tax Cuts and Jobs Act of 2017 Adjustment);
- Case U-20134 (Consumers Energy General Rates);
- Case U-20150 (UPPCO Revenue Decoupling Mechanism Complaint);
- Case U-20162 (DTE General Rates);
- Case U-20165 (Consumers Energy Integrated Resource Plan);
- Case U-20229 (UPPCO 2019 PSCR Plan Case);
- Case U-20276 (UPPCO General Rates);
- Case U-20350 (UPPCO Integrated Resource Plan);
- Case U-20359 (I&M 2019 General Rate Case);
- Case U-20471 (DTE Integrated Resource Plan);
- Case U-20479 (SEMCO 2019 General Rate Case);
- Case U-20561 (DTE 2019 General Rate Case).;

- Case U-20591 (Indian Michigan Power Company IRP);
- Case U-20642 (DTE Gas 2020 General Rate Case).;
- Case U-20649 (Consumers Electric Voluntary Green Pricing).;
- Case U-20650 (Consumers Gas 2020 General Rate Case);
- Case U-20697 (Consumers Electric 2020 General Rate Case);
- Case U-20713 (DTE 2020 Voluntary Green Pricing);
- Case U-20836 (DTE Electric 2022 General Rate Case);
- Case U-20874 (Alpena Power 2022-23 EWR Plan Case);
- Case U-20875 (Consumers Energy 2022-23 EWR Plan Case);
- Case U-20876 (DTE Electric 2022-23 EWR Plan Case);
- Case U-20877 (Indiana Michigan 2022-23 EWR Plan Case);
- Case U-20878 (NSP 2022-23 EWR Plan Case);
- Case U-20879 (UPPCO 2022-23 EWR Plan Case);
- Case U-20880 (UMERC 2022-23 EWR Plan Case);
- Case U-20881 (DTE Gas 2022-23 EWR Plan Case);
- Case U-20882 (MGU Gas 2022-23 EWR Plan Case);
- Case U-20883 (SEMCO Gas 2022-23 EWR Plan Case);
- Case U-20889 (Consumers Karn Retirement Securitization);
- Case U-20963 (Consumers Energy Electric Rate Case);
- Case U-21015 (DTE Securitization Case);
- Case U-21048 (Consumers Energy 2022 PSCR Plan);
- Case U-21081 (UMERC 2021 IRP);
- Case U-21090 (Consumers Energy 2021 IRP);

- Case U-21189 (Indiana Michigan 2022 IRP);
- Case U-21193 (DTE Electric 2022 IRP);
- Case U-21224 (Consumers Energy 2022 Electric Rate Case);
- Case U-21297 (DTE Electric 2023 Rate Case);
- Case U-21377 (IM Renewable Acquisition);
- Case U-21389 (Consumers Energy 2023 Electric Rate Case);
- Case U-21540 (MGU 2024 Gas Rate Case); and
- Case U-21555 (UPPCO 2024 Rate Case).

Additionally, I have testified as an expert witness before the Public Utilities Commission of Nevada in Case No. 16-07001 concerning the 2017-2036 integrated resource Plan of NV Energy; and before the Missouri Public Service Commission in Case Nos. ER-2016-0179, ER-2016-0285, and ET-2016-0246 concerning residential rate design and electric vehicle ("EV") policy, revenue requirements, cost of service, and rate design. I testified before the Kentucky Public Service Commission in Case No. 2016-00370 concerning municipal street lighting rates and technologies. I testified before the Massachusetts Department of Public Utilities in Case Nos. DPU 17-05 and DPU 17-13 concerning EV charging infrastructure program design and cost recovery. Before the Rhode Island Public Utilities Commission, in case 4780, I testified concerning Advanced Metering Infrastructure and EV charging infrastructure. Before the Delaware Public Service Commission, I testified regarding EV charging infrastructure in case 17-1094. I testified before the Georgia Public Service Commission in Case No. 4822 concerning PURPA avoided cost. I testified before the Colorado Public Utilities Commission in Cases No. 20A-

0204E and 20A-195E concerning cost recovery for EV charging infrastructure. I also testified before the Minnesota Public Utilities Commission in Case No. 22-432 regarding EV charging rate design.

I have also testified as an expert witness on behalf of the State of Michigan before the Federal Energy Regulatory Commission ("FERC") in cases relating to the relicensing of hydro-electric generation and have participated in state and federal court cases on behalf of the State of Michigan, concerning electricity generation matters, which were settled before trial.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit CUB-17: Resume of Douglas B. Jester

Exhibit CUB-18: *Reserved*

Exhibit CUB-19: Electric Vehicle Charging Profiles

II. SUMMARY

Q. What topics are you addressing in your testimony?

A. My testimony will address the following topics:

1. Rate recovery of outage bill credits;
2. Securitization of tree trimming surge costs;
3. Rate design issues;
4. Transportation electrification.

Q. Which Company witnesses' testimony do you discuss in your testimony?

A. I am addressing the testimony of Company witnesses Neal T. Foley, Habeeb J. Maroun, Aaron Willis, and Pina Bennett.

III. OVERVIEW OF DTE ELECTRIC'S APPLICATION

Q. Please summarize DTE Electric's rate request.

A. As presented in DTE Electric's Rate Case Summary, DTE Electric is proposing $456 million annual revenue increase, driven substantially ($285 million) by increases in rate base but with material increases due to cost of debt and capital structure ($36 million), increased return on equity ($63 million), and operating cost increases ($72 million). The rate base increase includes $927 million in utility plant additions. This revenue increase results in a 9.6% increase for residential customers, an 8.9% increase for secondary residential customers, a 4.3% increase for primary customers, a 2% reduction of rates for economic development customers (D13 XL), and 6% increase of lighting customers.

The underlying capital expenditures driving rate base increases are shown in Exhibit A-12 Schedule B5 and a substantial majority is to be spent on the DTE Electric's distribution system.

Q. How should the Commission approach this case?

A. DTE Electric's electricity costs are comparatively high for residential and commercial customers and average for industrial customers. DTE Electric's reliability is poor,

particularly when Major Event Days are included. The following table from CUB's annual utility performance report shows DTE Electric's comparative performance in 2021.[1]

2021 DTE Electric Company Performance Summary

Metric	Value	Michigan	US Average	IOU Rank
Number of Electricity Customers Across All Sectors	2249459	5014447		1
SAIDI with Major Event Days (Minutes)	927.4	873	440	7
SAIDI without Major Event Days (Minutes)	135.6	177.9	119.9	2
SAIFI with Major Event Days (# of Outages)	1.581	1.656	1.396	2
SAIFI without Major Event Days (# of Outages)	0.924	1.03	0.998	1
CAIDI with Major Event Days (Minutes)	586.6	527	315	7
CAIDI without Major Event Days (Minutes)	146.8	172.6	120.1	4
Residential Electricity Price ($)	0.17856	17.61	13.07	5
Commercial Electricity Price ($)	0.10519	11.69	9.81	1
Industrial Electricity Price ($)	0.06371	6.68	6.12	3
Residential Electricity Savings from Efficiency Programs as a % of Sales	1.747	1.405	0.846	3

In this case, DTE Electric proposes revenue increases well in excess of inflation rates. In general, and particularly when a utility has comparatively high rates, the Commission should be wary of rate increases that exceed general inflation. Generation fuel prices are volatile and technology mix is changing which can engender electricity price variation, but electricity generation, transmission, distribution, metering and utility operations are mature businesses that should show long-term trends of improving productivity and relative cost declines.[2]

[1] CUB Utility Performance Report 2023 Edition, p. 8. Data availability lags for some data used in the report cause a delay between the data year and the report year. The 2024 edition is currently in preparation.

[2] Direct testimony of Matthew Bandyk, pp. 3-4.

I therefore recommend that the Commission approach all rate cases from the perspective that a utility should be managing its operations to limit rate increases to the general inflation rate or less. At the same time, the Commission should be focused on ensuring that DTE Electric is accountable for improving distribution reliability.

IV. OUTAGE CREDIT RECOVERY

Q. What proposal is the Company making in this case with regard to outage credit recovery?

A. As described by DTE Electric witness Neal T. Foley,[3] the Company proposes that outage bill credits provided to customers pursuant to the Commission's Service Quality and Reliability Standards for Electric Distribution Systems (Mich Admin Code R460.701-752 that result from certain causes be deferred for subsequent recovery.

Q. For what causes of outages does DTE Electric propose to recover bill credits?

A. For bill credits paid when DTE Electric's restoration of service exceeds durations specified in the rules when the outage causes are:

- Transmission operator or other utility
- Public interference
- Animal interference

For bill credits paid when a DTE Electric customer experiences excessive outage frequency, the causes listed above for excessive outage duration and also outages caused by:

[3] Direct testimony of Neal T. Foley, NTF-30:12 through NTF-33:25.

- Ice
- Lightning
- Wind
- Other weather

Q. Do you agree with this proposal?

A. No. This proposal is reflective of DTE Electric's continuing resistance to accountability for its performance as owner and operator of its distribution system.

An outage attributable to a transmission operator or other utility must be fixed by that party. It is therefore reasonable to provide a limited recoverability of bill credits due to such outages, though the proper public policy would be that DTE Electric must recover that cost from the responsible party.

Aside from this limited exception, the Commission should reject this proposal. An outage duration exceeding the Commission's standards reflects DTE Electric's failure to timely repair the problem and restore service, even if the outage is caused by public interference or animal interference. If the outage is caused by public interference, DTE Electric can seek recourse from the responsible party and if that isn't possible, this is nonetheless a case in which DTE Electric should reasonably be expected to timely restore service. Animal interference is an event that DTE Electric and any other utility should expect to happen in its distribution system and which they should be prepared to timely repair.

The Commission's outage frequency limits, at 6 or more in a 12-month period, are already generous to the utility. DTE Electric's proposal to recover bill credits for weather

effectively excludes a majority of their outage occurrences and would completely undermine any accountability for ensuring that their distribution system is robust enough to provide satisfactory service. The Company's rationale "that the Company controls the restoration time when there is a weather event but not the frequency with which weather events occur"[4] is unavailing because the Company does control the vulnerability of its distribution system to weather.

Q. What other considerations apply to this proposal?

A. DTE Electric has persistently had amongst the worst reliability records of any investor-owned utility over several decades. The Commission has given considerable attention to this problem over those decades to little avail.[5] The rules in question are one of the few measures that the Commission has undertaken to hold utilities accountable for performance, albeit in a very modest way. The Commission has not reduced return on equity, held utility management to high standards, administered significant penalties for violation of the Service Quality Standards, nor taken any other actions to hold utilities accountable even as utilities spend billions on supposed distribution system improvements. For the Commission to grant this request by DTE Electric would demonstrate the Commission's abject inability to hold a utility accountable for its performance.

[4] Direct testimony of Neal T. Foley, NTF-32:15-19.

[5] See the presentation by Douglas Jester in the Commission's 2021 Technical Conference on Emergency Preparedness, Distribution Reliability, and Storm Response, available from https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/technical-conference/Session_2_Master_Slide_Deck_-_Tech_Conf_11-5-2021.pdf as of 20 July 2024.

V. TREE TRIMMING SURGE SECURITIZATION

Q. What proposals has DTE Electric made in this case regarding costs of its tree trimming surge?

A. DTE Electric has made two proposals. First, they propose that the Company be allowed a return on the tree trim regulatory asset accumulated as a result of the tree trim surge at the Company's long-term cost of permanent capital. MNSC Witness Paul Alvarez testifies in opposition to that proposal, and I endorse his testimony and recommendation.

Second, they describe their intent to securitize the costs of the tree trim surge after the surge program concludes, capturing all expenditures not previously securitized. I support that plan but strongly advise that DTE Electric assume that the same conditions will apply to this securitization as the Commission ordered in Case No. U-21015.

VI. RATE DESIGN

Q. Are there other considerations that the Commission should apply to changes in rate design?

A. Yes. As MNSC witness Graham Woolley shows, the effective capacity of the distribution system is seasonal. Currently aging of line transformers occurs almost exclusively occurs during Summer months June through August. As both he and MNSC witness David Gard show, utilization of the effective capacity of the distribution system is highly seasonal, both because nominal loads are lower in non-summer seasons but also because transformer effective rating is higher when ambient temperatures are lower. With capacity that varies seasonally, the proper basis for both cost of service and rate design of distribution costs is

the degree of capacity utilization, not nominal loading. On that basis, distribution system rates should be seasonal.

Additionally, I note that MNSC witness David Gard shows very clearly that the ratios of coincident and non-coincident peak demands to annual energy vary significantly within the broad residential class both as between single-family and multi-family dwelling types and according to the degree of electrification of buildings and automobiles. I reiterate and support his recommendation that these become the basis for separate residential customer rate classes in the future. In particular, I recommend that the Commission require DTE Electric to present in its next rate case a cost-of-service study and corresponding rates in which residential customers are divided into Multifamily, Single-Family with electric space heating, and Single-Family with fossil-fueled space heating. For these purposes, a Single-Family class should include duplexes and mobile homes since these appear to have similar load profiles. The Commission should also note that in addition to the load profile differences between Single-Family and Multi-Family dwellings, the infrastructure requirements in the form of utility-owned line transformers, service lines, etc., for a typical Multi-Family dwelling unit are often quite different from those for Single-Family buildings; it is therefore likely that there are material differences in distribution system costs caused by these two dwelling types.

I note that while this will add some complexity to the residential cost of service analysis, each of the resulting residential classes will be larger by both customer count and electricity demand than several of the commercial and industrial classes and all of the public lighting

classes. It would also be appropriate for the Commission to consider subdividing the Secondary Commercial General Service Rate class by space heating heat source.

Q. Witnesses David Gard and Graham Woolley present analyses focused on transformers. Does the argument apply to other elements of the distribution system?

A. Yes. We are presenting the transformer analysis to illustrate that this is a significant consideration, but ambient temperature is important to most elements of the distribution system and should be considered across all of those elements. For example, the current-carrying capacity (ampacity) of conductor is significantly influenced by ambient temperature as represented in the Neher-McGrath equation.[6] I have long found the ISO New England Capacity Rating Procedures document,[7] though old, a convenient reference to considerations of the effects of ambient temperature on transmission element ratings and those same considerations also apply to distribution systems as they are composed of similar but smaller elements.

Q. Doesn't DTE Electric already have separate rate schedules for both residential and commercial space heating?

A. Yes, but those rate schedules mostly require separate metering, which is an unnecessary expense to both DTE and the customer. Most are also interruptible, which may not appeal to all customers. Rate Schedule D1.7 is limited to geothermal (ground source) heating. Further, in the event that considerable building electrification occurs in future, as some

[6] Neher, J. H.; McGrath, M. H. (October 1957). "The Calculation of the Temperature Rise and Load Capability of Cable Systems". *AIEE Transactions*. **76** (III): 752–772.

[7] See capacity_rating_procedures.pdf (iso-ne.com).

current public policy favors, the aggregate of these excess metering and billing costs could become quite large. It will be less costly and more sustainable over the long term to simply treat customers with electric space heating as a separate class.

Q. What would be the benefits of the changes in rate design that you are recommending?

A. There are three principal benefits. First, both the use of seasonal rates and breaking up the residential class by dwelling type and space-heating technology will result in more accurate assignment of revenue responsibility to customers. At present, it is almost certainly the case that multi-family residential customers subsidize single-family residential customers and that customers that have electric space heating but do not have space heating separately metered are subsidizing customers that use fossil-fueled space heating. These overlap in that electric heating is a much larger share of Multi-Family housing than it is of Single-Family housing. An important consequence is likely that low-income households, who disproportionally occupy Multi-Family housing with electric heating are significantly subsidizing better-off households occupying Single-Family housing and using fossil-fueled heating. Appropriately separating these classes to determine cost of service and construct different rate schedules could significantly reduce current inequities in electric utility bills.

Second, such changes in rate design would provide price signals to residential customers that would guide equipment selection and other investments and energy consumption behavior that will, in the long run, reduce electric utility costs to society and individual customers.

Third, these changes in rate design will promote electrification by making electricity cheaper at the times space heating is needed, which will reduce pollution emissions and dilute utility fixed costs over higher sales.

Q. You did not recommend separate residential classes based on electric vehicle ownership or behind-the-meter generation. Why not?

A. With respect to electric vehicle ownership as a customer classifier, that is likely to change more quickly than home heating. Further, I recommend a different approach to managing electric vehicle charging in the portion of my testimony covering DTE Electric's Transportation Electrification Plan and electric vehicle charging programs.

With respect to behind-the-meter distributed generation, the Commission has already adopted the inflow-outflow framework and required a Rider for eligible customers that prescribes compensation for outflow. In the event that analysis shows that there should also be differences in inflow rates for such customers, that could also be done through the Rider as sur-credits on inflow rates. So, structurally it appears cleaner to not proliferate additional rate schedules to accommodate customer adoption of behind-the-meter distributed generation.

Q. Do you recommend that the Commission adopt these rate design changes in the present case?

A. No. Data are not available in this case for the full analysis of these recommendations. The analysis of rate designs based on these recommendations would be contingent on Commission decisions about cost-of-service treatment of Production Plant, seasonality of distribution system cost of service, classes to use in the analysis, and perhaps other things.

It would be more appropriate for the Commission to provide some guidance as to the rate design considerations that it would like to consider or adopt, and require DTE Electric to submit the requisite analyses and rate design recommendations in a future case.

Q. Please summarize your rate design recommendations to the Commission.

A. I recommend that the Commission require that DTE Electric file in its next rate case an analysis of the seasonality for cost causation of distribution costs and distribution rate designs consistent with that seasonality.

I recommend that the Commission require that DTE Electric file in its next rate case an alternative cost of service study that separates Residential customers into Multi-Family, Single-Family with electric space heating, and Single Family with fossil-fueled space heating, such that the Commission can decide in that case whether this approach should be adopted.

Finally, I recommend that the Commission encourage DTE Electric to engage with stakeholders in performing these analyses, rather than waiting until the next rate case is filed.

VII. <u>TRANSPORTATION ELECTRIFICATION</u>

Q. Please summarize DTE Electric's Transportation Electrification proposals in this case?

A. In this case, DTE Electric presents

- an analysis of cost of service and rate design if Direct Current ("DC") Fast Chargers are treated as a separate class, covered in the testimony of Habeeb Maroun[8] and Aaron Willis[9];
- its Transportation Electrification Plan ("TEP" or "Plan"), including background on the Company's development of the TEP;[10] DTE's proposed TEP program portfolio;[11] a benefit-cost analysis of the TEP;[12] and the proposed investments associated with the TEP.[13]

Within this presentation, DTE Electric proposes:

- To not implement a DC Fast Charging class in cost-of-service analysis or a distinct DC Fast Charging rate at this time, but to revisit these in the future when the DC Fast Charging customer base is larger and utilization is nearer market equilibrium;[14]
- To charge a customer installing electric vehicle charging Contribution in Aid of Construction ("CIAC") consistent with existing line extension policy with an allowance for expected revenue from that specific charger;[15]

[8] Direct Testimony of Habeeb J Maroun, HJM-27:9 through HJM-25:20.

[9] Direct Testimony of Aaron Willis, AW-34:15 through AW-36:17.

[10] Direct Testimony of Pina Bennett, PB-14:15 through PB-37:6.

[11] Direct Testimony of Pina Bennett, PB-37:8 through PB-52:17.

[12] Direct Testimony of Pina Bennett, PB 52:19 through PB-59:21.

[13] Direct Testimony of Pina Bennett, PB-59:23 through PB-62:15.

[14] Direct Testimony of Aaron Willis, AW-36:12-17.

[15] Direct Testimony of Pina Bennett, PB-35:3-4.

- To base its spending plans on its own forecast of electric vehicle adoption in its service territory;[16]
- To not include utility-owned pole-mounted chargers in this initial TEP;[17]
- To offer customers rebates for installing electric vehicle charging infrastructure as summarized in Table 9 of the testimony of Pina Bennett,[18] with rebate amounts set at levels intended to offset CIAC costs for program participants only in limited cases;[19]
- To require low-income customers obtaining a home charger rebate to use an ENERGY STAR or vehicle manufacturer charger less than 12 kW and enrollment in a Time-of-Day rate;[20]
- To require recipients of Business Charger rebates to use networked chargers, share data with DTE Electric, and maintain 97% charger uptime, with additional requirements for larger rebates available to businesses located in a disadvantaged community or in rural areas;[21]
- To require Multi-unit Dwelling installations to meet certain low-income/disadvantaged community criteria and to use a networked charger,

[16] Direct Testimony of Pin Bennett, PB-35:5-6.

[17] Direct Testimony of Pina Bennett, PB-35:7.

[18] Direct Testimony of Pina Bennett, PB-38, Table 9.

[19] See Direct Testimony of Pina Bennett, PB-42:19-25 (describing rebates for qualified low-income MUDs as intended to cover "the CIAC portion of the utility make-ready and the customer make-ready.").

[20] Direct Testimony of Pina Bennett, PB-41:11 through PB-42:3.

[21] Direct Testimony of Pina Bennett, PB-47:8-17.

authorize data sharing with DTE Electric, commit to 97% charger uptime, and have demonstrated tenant interest in installing electric vehicle chargers;[22]

- To require recipients of Fleet Charging rebates, including for transit bus and school bus charging, to install a qualified, networked charger, authorize data sharing with DTE Electric and commit to demand ceilings in constrained areas and for school bus chargers to include vehicle-to-grid chargers for a greater rebate;[23]
- To not support rebates for workplace charging on the basis that there is sufficient incentive for workplaces to install chargers to attract employees;[24]
- To discount rebates to Electric Choice customers.[25]

To implement the proposed TEP portfolio, DTE requests approval of approximately $25 million in the 2025 projected test year, of which about $1.6 million will be capital for Information Technology capabilities to support the Program, about $3.2 million will be expenses for program administration and education and outreach, and about $20.1 million of expenditures for customer rebates and an Emerging Technology Fund will be booked as a regulatory asset to defer cost recovery.

Q. What is your assessment of DTE Electric's proposed TEP?

A. DTE Electric's TEP is a positive development and I urge DTE Electric and the Commission to continue with periodic revisions and implementation of such plans. I have a few specific

[22] Direct Testimony of Pina Bennett, PB-44:4 through PB-45:3.

[23] Direct Testimony of Pina Bennett, PB-49:8-15.

[24] Direct Testimony of Pina Bennett, PB-50:16-18.

[25] Direct Testimony of Pina Bennett, PB-50:19-22.

concerns about this Plan, and find that the benefit-cost analysis is incorrect and should not be the basis for limits to this and future TEPs.

Q. What are your specific concerns about the Transportation Electrification Program?

A. My principal concern is DTE Electric's decision to apply CIAC practices to electric vehicle charging based on current line extension policy. I also find the decision not to support workplace charging to be blind to some specific circumstances in which support should be provided. The proposal to discount rebates to Electric Choice customers is based on incorrect premises. The Plan gives insufficient attention to the integration of vehicle charging into the grid as electric vehicle adoption reaches high levels, and likewise gives insufficient attention as to how TEP programs may support or complement federal funding for EV charging and transportation electrification initiatives.

Q. What is your concern about the application of line extension policy for installation of electric vehicle charging?

A. It is highly likely that this policy will create unwarranted inequities and barriers to electric vehicle adoption. Customers who happen to be located in places where distribution system infrastructure is saturated will pay to upgrade the distribution system while customers who happen to be located where there is surplus capacity will not. As electric vehicle adoption proceeds, early adopters in a residential or commercial neighborhood may not need to pay CIAC but at some point capacity limits will be reached and the unfortunate customer who happens to adopt an electric vehicle at the wrong time will be asked to pay CIAC, and the upgrade will then provide capacity for many subsequent adopters who will not have to pay CIAC. A similar pattern could occur with DC Fast Charging; for example, an area near a

highway exit could host a few DC Fast Chargers without expense then reach a capacity limit such that the next DC Fast Charger installation would incur significant CIAC. Word of mouth information about large utility upgrade costs for electric vehicle adoption will discourage people from adoption and discourage commercial installers from developing a sufficient network of public charging infrastructure, particularly DC Fast Charging, which DTE correctly assesses will fulfill the majority of public charging needs.[26]

DTE Electric's forecast of electric vehicle adoption is that it will be widespread and perhaps ubiquitous.[27] Under these circumstances, rather than randomly charge some customers CIAC while many others do not pay CIAC, based on conditions that are not under their control, it would be far better policy to socialize the costs of grid upgrades to accommodate electric vehicle charging. I therefore recommend that the Commission direct DTE to waive CIAC for all new residential and commercial installations of EV charging, whether installing customers are participants in DTE's TEP programs or not. This would extend and expand the Company's prior policy of waiving CIAC for participants in the Charging Forward programs.

By socializing the costs of grid upgrades, those costs can then be paid out of the aggregate new revenue that will be provided by electric vehicle charging across DTE's distribution system, rather than expecting that revenue from each individual charging location will cover the costs that happen to be incurred by that particular charging location at that particular time. The cost of such grid upgrades should be considered as part of any benefit-

[26] Direct Testimony of Pina Bennett, PB-26, Table 4.

[27] Direct Testimony of Pina Bennett, PB-23:5 through 25:4.

cost analysis or ratepayer impact analysis of the Company's transportation electrification programs and investments.

Q. In what circumstances might support for workplace charging be appropriate?

A. It is likely often the case that employers with private parking for employees will find it useful to provide electric vehicle charging for employees. However, workplace charging is not always privately held by the employer and may be shared (as at a shopping mall or multi-tenant office building), in common area parking in a downtown district, or in municipally owned parking. In these cases, employees seeking electric vehicle charging may encounter the same difficulties that DTE Electric recognizes for multi-unit dwellers. It would be appropriate to extend the rebate program to these circumstances.

Q. What is wrong with DTE's premises for discounting rebates to Electric Choice customers?

A. The stated premise is that Electric Choice customers contribute less revenue to DTE Electric than full-service customers, so a discount is appropriate. However, it is not gross revenue that supports electric vehicle charging programs, but net revenue where the principal cost that must be netted out is the cost of power supply. Net revenue is almost entirely attributable to paying full rates for charging while the utility does not incur corresponding costs for distribution system upgrades. Net revenue from charging at the premises of an Electric Choice customer is likely to be similar to net revenue from charging at the premises of a full-service customer.

Q. What more should DTE Electric do to address integration of vehicle charging into the

grid as electric vehicles reach higher levels of adoption?

A. DTE Electric has taken some reasonable first steps to integrate electric vehicle charging into the grid by encouraging or requiring customers participating in its Charging Forward programs to use Time-of-Day rates and by initiating the pilot DTE Smart Charge program. I generally support continuing to condition customers' participation in the Company's TEP programs on their agreement to manage their EV charging load.

To demonstrate that Time-of-Day rates are likely to be insufficient in the long run, I modeled load profiles in two scenarios using the National Renewable Energy Laboratory's EVI-Pro Lite tool.[28] In both cases, I used the Detroit urban area for the analysis and developed the load profile for charging 40,000 electric vehicles. The results are shown in Exhibit CUB-19. The specifications of each scenario are shown in the Exhibit next to the charging load profiles. In the first scenario, charging at home is assumed to be delayed until midnight, as someone might program their car or home charging station to do if they take service on a Time-of-Day rate in which the low-cost period begins at midnight. In the second scenario, charging at home is assumed to begin immediately after the car returns home from the last trip of the day but the charging is spread evenly as slowly as possible for readiness the next morning. It should be noted that the vertical axes have different scales in the two scenarios. The first scenario, which is very like DTE Electric's current approach to grid integration of electric vehicle charging, produces a very high demand immediately upon the start of the low-priced period at midnight, and then diminishes fairly quickly overnight and has comparatively low charging demand through the rest of the day. The

[28] Accessible at https://widgets.nrel.gov/eere/evi-pro-lite/#/load-profile.

second scenario has a much more even demand throughout the day and will be much easier to match to generation. Further, the second scenario would be much easier to accommodate in the distribution grid.

Additionally, DTE Electric has not compared charging profiles to the expected grid load net of renewables. As DTE Electric and other Michigan utilities increase their renewable energy portfolios to meet recently adopted renewable and clean energy standards, the best time of day to charge is likely to evolve and perhaps be seasonal. Flexibility to avoid charging during extended periods of low renewable generation and to fully charge during periods of high renewable generation, and especially if renewable curtailment will otherwise occur, will also be valuable. Such flexibility is difficult if not impossible to capture in a static rate design. DTE Electric's current Transportation Electrification Plan seems to assume that grid conditions will remain as they are now and does not account for dynamics due to transportation electrification and increasing renewable generation.

I recommend that the Commission require DTE Electric to provide 8760-hour annual load profiles in addition to the other metrics the Company proposes to track[29] to enable stakeholders to work on this problem.

I also recommend that the Commission require DTE Electric to prepare a supplement to its Transportation Electrification Plan that addresses grid integration of electric vehicle charging by providing a forecast of load profiles at line transformers, circuit feeder origination at the substation, and at generation when electric vehicle charging is combined

[29] Direct Testimony of Pina Bennett, PB-52:1-17.

with existing loads at various levels of electric vehicle adoption and by also providing an analysis of load net of renewable generation at various levels of electric vehicle adoption with Michigan attaining 50% renewables, 60% renewables, and 80% renewables. Challenges exposed by these analyses should then be addressed through plans or pilot projects, which may include managed charging programs and/or dynamic rate designs akin to those identified by the Company in its survey of sister utilities' TEPs.[30]

Q. What more should DTE Electric do to ensure its TEP programs support and complement federal funding and initiatives for transportation electrification?

A. DTE Electric's proposed TEP programs recognize some federal transportation electrification efforts. For example, the Company would require rebate recipients in the Business Charger and Multi-family programs to meet uptime standards aligned with federal standards for National Electric Vehicle Initiative. It also recognizes "support to on-route DCFCs not in DAC or rural areas" is "critical in the near-term to decrease range anxiety and to complement federal funding opportunities, such as the NEVI program."[31]

However, there is considerable room for improvement.

DTE Electric's proposed TEP programs partially recognize the value of alignment with some federal transportation electrification efforts. For example, the Company would require recipients of rebates for on-route charging as part of the Business Charger Rebates

[30] Direct Testimony of Pina Bennett, PB-16:3 through 23:3 (noting the prevalence of "requirements or incentives that support managed charging or Time of Day rates" in other utilities' TEPs).

[31] Direct Testimony of Pina Bennett, PB-46:22-25.

program to meet uptime standards[32] that are aligned with the federal standards for National Electric Vehicle Infrastructure ("NEVI") program. And, to qualify for higher rebate amounts for on-route charging, participants would need to locate charging in disadvantaged communities as defined by the Michigan State Plan for EV Infrastructure Deployment (a plan developed pursuant to the NEVI program) or a rural area as defined by the U.S. Department of Transportation.[33] DTE further recognizes that "support to on-route DCFCs not in DAC or rural areas" is "critical in the near-term to decrease range anxiety and to complement federal funding opportunities, such as the NEVI program."[34]

At the same time, there is room for greater coordination. First, DTE's Business Charger Rebate program for on-route charging directly overlaps with the market segment to be served by the state through its limited NEVI funding,[35] which, for select projects, provides support for up to 80% of the project cost. NEVI funds may not be used for major grid upgrades and federal guidance discourages use of funds for any utility-side costs, instead encouraging states to "explore whether they could be covered by electric utilities ... so as to minimize use of NEVI funds for grid upgrades where possible."[36] To connect these programs and stretch Michigan's limited NEVI funds further, DTE's rebates for on-route charging should be available for "utility make-ready," which the Company defines to include "upgrades on the utility side of the meter, from the line transformer to the meter,"

[32] Direct Testimony of Pina Bennet, PB-47:10-12.

[33] Direct Testimony of Pina Bennett, PB-47:14-17.

[34] Direct Testimony of Pina Bennett, PB-46:22-25.

[35] Michigan's funding is ~$110M. See https://www.ampeco.com/blog/nevi-program-faq/.

[36] https://www.ampeco.com/blog/nevi-program-faq/.

as well as "customer make-ready," which includes "upgrades on the customer side of the meter, from after the meter to the EV charger." Unfortunately, DTE's testimony does not specify whether the Business Charger Program rebates will be available for those cost categories or available only for the "EV Charger." I therefore recommend that DTE clarify that its Business Charger Rebates for on-route charging are available to defray utility make-ready, customer make-ready and EV charger costs as defined in Table 7 of Witness Bennett's testimony.[37]

Second, to the extent practical, DTE should prioritize Business Charger Rebate program applications from prospective participants that are also seeking (or have secured) funding through the state's NEVI program. Such coordination is consistent with the Commission's directive in U-21297 "requiring the [Business Charger Rebate] program [to] be coordinated with NEVI as ... that may enhance the program's goals."[38] Relatedly, DTE should work with prospective program participants to site EV charging stations within census tracts eligible for the Alternative Fuel Vehicle Refueling Property Tax Credit as extended and modified by the Inflation Reduction Act.

Third, with respect to the eFleet Charger Rebate for school and transit buses, the Company should similarly seek to prioritize applicants that are seeking (or have secured) funding through federal programs for zero-emission buses, like the Clean School Bus program and the Low or No Emissions Grant Program for transit buses. Through its education and outreach efforts, DTE should support transit agency or school districts' efforts to secure

[37] Direct Testimony of Pina Bennett, PB-36:1-4.

[38] Case No. U-21297, Dec. 1, 2023, Order, p. 266.

such grants through technical assistance and grant-writing support. DTE also should clarify that rebates are available for "utility make-ready" and "customer make-ready" in addition to EV Chargers, as some of these costs are not eligible expenses with federal grants and use of DTE rebates for those expenses can therefore help applicants access those grant funds and stretch those grant funds farther. Finally, DTE should work with prospective eFleet Charger Rebate program participants to site EV charging stations within census tracts eligible for the Alternative Fuel Vehicle Refueling Property Tax Credit.

Q. In what ways do you find DTE Electric's Benefit-Cost Analysis to be incorrect?

A. The analysis that DTE Electric presents as its benefit-cost analysis is essentially a rate-payer impact analysis and not a benefit-cost analysis. DTE counts as "benefits" the payments that electric vehicle drivers pay to DTE Electric and counts as "costs" the expenditures that DTE Electric must make to supply power for electric vehicle charging, to upgrade distribution systems, and to provide programs and rebates for electric vehicle charging. The difference between the incremental revenue to DTE Electric and costs will, in the normal course of utility regulation, accrue to DTE Electric's customers in the form of diluted rates for other uses of power. This is a ratepayer impact analysis. It is also a legitimate consideration, as the Commission should be wary of cross-subsidization of customers. However, it ignores that the electric vehicle charging revenue that exceeds the utility costs of electric vehicle charging support by the utility is a subsidy by electric vehicle drivers to other customers. From the perspective of benefit-cost analysis, it is a transfer payment between parties and is not a benefit. Similarly, rebates from the utility to electric vehicle drivers, paid for by other customers, are also a transfer payment and not a cost. DTE Electric's analysis simply demonstrates that even with the TEP programs it proposes,

there will be a net subsidy from electric vehicle drivers to other utility customers. This is a valuable demonstration that helps to justify the scale of DTE's proposed TEP and strongly supports its approval by the Commission, but it is not accurate to describe DTE's analysis as a "benefit-cost analysis" because it fails to consider the full range of costs and benefits associated with the TEP.

Q. What costs and benefits should be included in a benefit-cost analysis of DTE's TEP?

A. The National Standard Practice Manual produced by the National Energy Screening Project[39] is a good guide to benefit-cost analysis. Additionally, the Commission should note that it has long used reasonably sound benefit-cost analyses for Energy Waste Reduction or Energy Optimization programs and has recently required appropriate benefit analyses in support of its grants under the Low-Carbon Energy Infrastructure Grants program.

In essence, a sound benefit-cost analysis should identify for the whole of society and from the perspective of various stakeholders the costs of the proposed course of action and the avoided costs and externalities associated with the course of action. In the specific case of a Transportation Electrification Plan, the full list of costs and benefits would include the cost of the electric vehicle set against the avoided cost of the non-electric vehicle alternative, the utility's incremental cost of producing and distributing electricity for vehicle charging, the avoided cost of avoided fossil fuels, the change in maintenance costs of an electric vehicle versus the avoided maintenance of a traditional vehicle, the climate

[39] Which can be obtained from https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/.

costs of supplying power for electric vehicle charging offset by the avoided climate costs of fossil fuel for a traditional vehicle, the health costs of electricity supply for electric vehicle charging offset by the avoided health costs of avoided transportation fuel production and combustion, avoided economic and national security risks and readiness costs due to reduced dependence on volatile international oil markets, and any other cognizable costs and benefits.

Because the purchase of an electric vehicle by a DTE Electric customer would be voluntary on the part of that customer (albeit in the context of the market effects of current regulations), it would be reasonable to assume that the private benefits plus any rebates from the utility will exceed the private costs of that customer so that the utility analysis could focus on externalities and utility costs.

Q. What is the consequence of DTE Electric excluding the full range of costs and benefits from its analysis of the TEP?

A. DTE's limited analysis could lead the Company and Commission to incorrectly assess the proper level of funding for DTE Electric's TEP programs.

Q. Does DTE Electric's analysis of ratepayer impacts of its program have value to the Commission?

A. Yes, it is appropriate that the Commission consider the impacts of this program on non-participating customers and perhaps even to seek to ensure that there is not a net cost to those non-participating customers (though I note that this condition is not imposed on utility Energy Waste Reduction programs).

Q. Do you have any concerns about DTE Electric's analysis of ratepayer impacts of

electric vehicle adoption?

A. Yes. DTE attempts to attribute only a portion of electric vehicle adoption to its TEP, which I do not believe is appropriate for a ratepayer impact analysis. Instead, DTE should assess marginal revenues from EVs on a service territory and system-wide basis. This the most natural basis for assessing ratepayer impact and the most reasonable approach from a policy perspective because the total number of EVs and associated net revenue from EV charging can be reasonably calculated. This approach is also justified by analogy to line extensions, where current allowances for line extension recognize that a new customer provides revenue that will fund at least a portion of the capital expenditures that are incurred for line extension, without discounting that incremental revenue by excluding line extensions that would occur anyway without the utility allowance. I am certain that if utility allowances for line extensions were based on the percentage of line extensions that would not occur without DTE's utility allowances, there would be very little or no utility contribution to line extensions.

Q. What do you recommend the Commission decide in this case regarding Transportation Electrification?

A. I recommend that the Commission generally support DTE Electric's proposed spending, without endorsing the benefit-cost analysis as presented. I also strongly recommend that the Commission direct DTE Electric to exempt from CIAC all distribution upgrades for electric vehicle charging infrastructure. I further recommend that the Commission direct DTE Electric to include full 8760-hour annual load profiles for electric vehicle charging amongst the metrics that it will track and in future provide to the Commission and stakeholders, and to prepare and file a supplement to the Transportation Electrification Plan

that projects the combined effects of transportation electrification and compliance with Michigan's renewable and clean energy standards on grid balance, as described above.

VIII. RECOMMENDATIONS

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

A. On behalf of MNSC, I recommend that the Commission:

(1) Reject DTE Electric's request to recover some outage bill credits;

(2) Agree to DTE Electric's proposal to securitize tree trim surge expenses once the surge is complete, but limit return on the deferred costs to short-term debt rates;

(3) Direct DTE Electric to submit in its next rate case a seasonal approach to distribution rates reflecting that the relative utilization of its distribution system is seasonal;

(4) Direct DTE Electric to evaluate separating the residential customer class into Multi-Family, Single-Family with fossil-fueled heat, and Single Family with electric heat in both the cost-of-service study and rate design, through an alternate cost-of-service study.

(5) Approve DTE Electric's proposed spending to implement its Transportation Electrification Plan, including its proposal to defer recovery of rebates, without endorsing DTE Electric's benefit-cost analysis.

(6) Reject DTE Electric's proposal to subject utility make-ready costs to Contribution in Aid of Construction similar to line extensions.

(7) Accept DTE Electric's recommendation to not act in this case on a separate class for DC Fast Chargers.

(8) Direct DTE Electric to include full 8760-hour annual load profiles for electric vehicle charging amongst the metrics that it will track

(9) Direct DTE Electric to prepare and file a supplement to the Transportation Electrification Plan that projects the combined effects of transportation electrification and compliance with Michigan's renewable and clean energy standards on grid balance, and strategies to address any related challenges.

Q. Does that complete your testimony?

A. Yes, it does.

MS. ANDREWS: Thank you. Next, on behalf of the Citizens Utility Board of Michigan, the Michigan Environmental Council, and the Natural Resources Defense Council, I'd move for the admission of the Direct Testimony of David Gard, which consists of a cover page, table of contents, 11 pages of question and answers, together with the admission of Exhibits CUB-20 through CUB-29.

JUDGE WALLACE: All right. Is there any -- is there any objection to binding in the direct testimony of Mr. Gard?

Hearing none, the testimony is bound in.

Is there any objection to the admission of Exhibit CUB-20 through CUB-29?

Hearing none, those exhibits are admitted.

(Testimony bound in.)

- - -

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **DTE ENERGY 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.	U-21534

DIRECT TESTIMONY OF DAVID L. GARD

ON BEHALF OF

CITIZENS UTILITY BOARD OF MICHIGAN,
MICHIGAN ENVIRONMENTAL COUNCIL,
NATURAL RESOURCES DEFENSE COUNCIL

July 25, 2024

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DIRECT TESTIMONY OF DAVID GARD FOR CUB, MEC & NRDC
CASE NO. U-21534

I. INTRODUCTION & QUALIFICATIONS

Q. Please state for the record your name, position, and business address.

A. My name is David L. Gard. I am a senior consultant at 5 Lakes Energy, a Michigan limited liability corporation, located at Suite 218, 220 MAC Avenue, East Lansing, Michigan 48823.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of Citizens Utility Board of Michigan (CUB), Michigan Environmental Council (MEC), and Natural Resources Defense Council (NRDC).

Q. Please summarize your experience in the field of utility regulation.

A. I have worked for 5 Lakes Energy since November 2014. In this role, I have done extensive modeling in support of resource planning and building decarbonization. Previously I directed the Michigan Environmental Council's energy policy program for more than a decade. My work experience is summarized in my resume, provided as Exhibit CUB-20.

Q. Please summarize your professional development coursework in the field of utility regulation.

A. I have completed this NRRI Regulatory Training Initiative course: Regulating Public Utility Performance (January 10, 2022 to March 28, 2022). I have also completed these EUCI courses: Utility Forecasting Techniques & Applications (March 22-23, 2021); Electric Cost-of-Service: Essential Concepts for a Changing Industry (July 15-16, 2019); Natural Gas Physical & Financial Markets (May 9, 2018); Introduction to the Natural Gas Industry, Infrastructure and Regulations (May 8, 2018); and Evolution of Electricity Markets: Disruptive Innovation & Economic Impacts (January 29-30, 2018). I also

completed the MSU Institute for Public Utilities course Accounting and Ratemaking (September 21-23, 2020).

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

A. I have previously testified before the Michigan Public Service Commission (Commission) in the following cases:

- Case U-20561 (DTE Energy Company 2019 General Rate Case);
- Case U-20963 (Consumers Energy Company 2021 General Rate Case);
- Case U-21090 (Consumers Energy Company 2021 Integrated Resource Plan Case).

In addition, I prepared written testimony based on my review of electric and gas utility energy efficiency potential studies in cases D.P.U. 18-110 through D.P.U. 18-119 before the Commonwealth of Massachusetts Department of Public Utilities.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit CUB-20:	Resume of David L. Gard
Exhibit CUB-21:	8760-hour load profiles for ResStock single-family and multi-family
Exhibit CUB-22:	CP and NCP performance of ResStock single-family, ResStock multi-family, and DTE 2018 residential
Exhibit CUB-23:	CP and NCP radar plots for ResStock single-family, ResStock multi-family, and DTE 2018 residential
Exhibit CUB-24:	Description of Modeling Analysis to Investigate Increased Building Electrification and Other Measures on Residential Hourly Load

Exhibit CUB-25: 8760-hour load profiles for eight scenarios

Exhibit CUB-26: Annual energy results for eight scenarios

Exhibit CUB-27: CP and NCP performance of eight scenarios

Exhibit CUB-28: CP radar plots for eight scenarios

Exhibit CUB-29: NCP radar plots for eight scenarios

II. SUMMARY

Q. What topics are you addressing in your testimony?

A. On behalf of CUB, MEC, and NRDC, I am addressing the following three topics:

- Comparing load profile shapes of single-family and multi-family residential customers;
- The importance of realistic building electrification projections;
- Simulating increased building electrification and other measures.

III. COMPARING LOAD PROFILE SHAPES OF SINGLE-FAMILY AND MULTI-FAMILY RESIDENTIAL CUSTOMERS

Q. Does the Company include all residential customers in a single class?

A. Yes.

Q. Why might this be inappropriate?

A. If subcategories of residential customers were shown to have meaningfully different cost of service characteristics, then it would be inappropriate to treat them within the same

customer class.

Q. Describe your comparison of single-family and multi-family load profiles in Southeastern Michigan.

A. Using the National Renewable Energy Laboratory's (NREL) realistic building load profiles available in its ResStock dataset, I created a representation of the Company's residential load by aggregating data for the five Southeastern Michigan counties of Lapeer, Macomb, Oakland, St. Clair, Wayne. Because ResStock data are reported separately for different building types, I was able to deconstruct the 5-county total residential electricity load profile into separate load profiles for single-family and multi-family residential subcategories.

Q. How do the 8760-hour load profiles compare?

A. Exhibit CUB-21 shows the 8760-hour load profiles for the single-family and multi-family residential subcategories. These are noticeably different. For instance, the single-family load profile shape demonstrates higher summer peaks and less wintertime load than the multi-family load profile shape.

Q. How do cost of service (COS) parameters compare?

A. Exhibit CUB-22 presents COS factors which were computed for ResStock single-family, ResStock multi-family, and DTE residential using the Company's 2018 COS results obtained from filed document "Part III Attachment 5 (29) COMPLETE".[1] To facilitate a more intuitive visual comparison, this same information is presented in a series of radar

[1] 2018 COS results were used for consistency with ResStock which reflects weather year 2018.

plots in Exhibit CUB-23. The differently shaped plots for single-family and multi-family households are readily apparent for both critical peak (CP) and noncoincident peak (NCP) COS parameters. Also, the close similarity between the ResStock single-family and DTE 2018 residential plots is plain to see, suggesting that the unique multi-family load profile shape is largely hidden within the Company's residential customer class.

Q. What do you recommend based on your analysis?

A. Given this strong evidence that single-family and multi-family residential customers have meaningfully different COS characteristics, I recommend that the Michigan Public Service Commission require the Company to conduct a similar analysis of its residential customers to determine whether continuing to combine single-family and multi-family customers within a single class is justified.

IV. THE IMPORTANCE OF REALISTIC BUILDING ELECTRIFICATION PROJECTIONS

Q. Please define the term "building electrification."

A. According to the U.S. Green Building Council, "Building electrification—also known as beneficial electrification or building decarbonization—describes the shift to using electricity rather than burning fossil fuels like oil, gas and coal for heating and cooking." I consider this to be a good working definition of the term.[2]

[2] See https://www.usgbc.org/articles/building-electrification-why-it-matters, last checked July 17, 2024.

Q. Is it reasonable to assume more building electrification within the Company's service territory over time?

A. Yes, I expect to see more building electrification in Southeast Michigan in the years ahead. Among various indicators of this trend are these:

- Mitsubishi and other manufacturers have made recent advances in heat pump technology. Cold-climate air source heat pumps are now available which operate more efficiently at lower ambient temperatures than older models.
- There is growing interest among Michigan communities in electrification as a strategy to reduce carbon emissions and improve local resilience. For example, the City of Ann Arbor has a program to promote home electrification.[3]
- The State of Michigan has embraced a goal to "reduce emissions related to heating Michigan homes and businesses by 17 percent by 2030."[4]
- Michigan Public Act 229 of 2023 Section 71(6) includes this provision for building electrification: "Beginning January 1, 2025, an electricity provider shall file its energy waste reduction plan as part of a customer energy optimization plan. A customer energy optimization plan shall include an energy waste reduction plan and may include an efficient electrification measures plan."

[3] See https://www.a2gov.org/departments/sustainability/Sustainability-Me/Families-Individuals/Pages/Home-Electrification.aspx, last checked July 17, 2024.

[4] MI Healthy Climate Plan, Michigan Department of Environment, Great Lakes, and Energy, p. 5, April 2022.

Q. Has the Company acknowledged the potential for more building electrification in the future?

A. Yes. I found references or allusions to anticipated building electrification in the Company's testimony on the following pages:

- Witness Deol: SSD-6, SSD-13, SSD-26, SSD-81, SSD-83
- Witness Hartwick: SMH-45, SMH-94, SMH-137, SMH-183
- Witness Kryscynski: AJK-25, AJK-31, AJK-34, AJK-35, AJK-76.

Q. Why is it important for the Company to include realistic projections of building electrification in its load forecasting?

A. Converting end uses such as space and water heating to electricity can cause significant changes in annual electricity use and in the size and timing of peak loads. Realistic projections of these changes are needed to properly plan the future distribution system. In addition, fair and effective rate design depends on such projections to inform the cost of serving customers who adopt building electrification.

V. SIMULATING INCREASED BUILDING ELECTRIFICATION AND OTHER MEASURES

Q. Briefly describe the simulation analysis you conducted for this case.

A. I created an Excel spreadsheet model (described in detail in Exhibit CUB-24) to simulate the effects of building electrification and other measures on residential hourly load. By focusing on the single-family detached building type, the effort was kept manageable while still reflecting a large number of customers in the Company's service territory. I used this

model to evaluate several scenarios compared to a baseline. The results are indicative of load shape changes in response to greater adoption of these building measures.

Q. Why did you conduct this analysis?

A. My purpose was to demonstrate the type of simulation that should be required of the Company to study the impacts of future building electrification on the distribution system and on cost of service.

Q. Which specific simulations did you run?

A. Table 1 lists eight combinations of building electrification (BE) adoption, electric vehicle (EV) adoption, and on-site photovoltaic (PV) production which I simulated. The BE adoption level of 44 percent, computed using outputs from Witness Graham Woolley's transformer aging model, represents the scale of building electrification possible on the system without exceeding the distribution transformer network's present design capacity (as explained in Exhibit CUB-24). The magnitude of this result suggests that a sizeable amount of building electrification could be accommodated without significant upgrades to the transformer network's capacity. This needs further study.

Table 1. Modeling Scenarios

Scenario Name	Building Electrification Adoption Rate	Number of EVs per Household	On-Site PV Production (Portion of Annual Load)
Baseline	0%	0	0%
44% BE	44%	0	0%
100% BE	100%	0	0%
44% BE_1 EV	44%	1	0%
44% BE_2 EV	44%	2	0%
44% BE_2 EV_5% PV	44%	2	5%
44% BE_2 EV_15% PV	44%	2	15%
44% BE_2 EV_25% PV	44%	2	25%

Q. What are the results of running these eight simulations?

A. Exhibit CUB-25 compares the resulting 8760-hour load profiles for all eight scenarios using a common y-axis scale. As building electrification increases, much of the additional load occurs during the winter heating season with the annual peak eventually shifting to winter. Adding EVs further increases load throughout the year with the general shape of the profile still being largely determined by the amount of building electrification. This is signified by the negative kWh in some hours in the last three graphs.

Exhibit CUB-26 shows the annual load in each case. Note thatthe 100% BE scenario results in slightly less annual load than adding one EV to the 44% BE scenario although the annual peak is noticeably greater in the 100% BE case. This more complicated result points to the need for simulating realistic combinations of building electrification and other measures such as EV charging when studying future load.

It is also instructive to examine the performance of each scenario relative to the Company's 2018 COS metrics. Exhibit CUB-27 presents these numerical results for CP and NCP. Exhibits CUB-28 and CUB-29 show this information in a series of radar plots. These plots show that critical peaks in colder months tend to increase with building electrification while those in warmer months tend to decrease slightly. This latter result can be explained by the model's application of simulated building envelope upgrades reducing air conditioning load. (See Exhibit CUB-24, p. 3 for an explanation.)

Q. What do you take away from these results?

A. As we look ahead to more building electrification, EV charging, and on-site PV production, load profiles can change dramatically depending on the choices customers make in

adopting these technologies. It is important not to discourage these choices with rate designs that do not accurately reflect COS. The radar plots, in particular, clearly suggest that load profiles for households which install electric heating equipment are noticeably different. A consequence of applying identical COS factors, based on a summer peak, to both non-electric and electric heating customers is that those with electric heating will be relatively overcharged, and the benefit of their annual peak occurring during winter when more system capacity is available will not be fully captured.

Q. What do you recommend based on this observation?

A. I recommend that the Michigan Public Service Commission direct the Company to provide a robustly time-differentiated rate structure that is available to electric heating customers and treat these customers as a separate class for the purpose of COS analysis and rate design.

Q. What else do you recommend based on the modeling analysis you conducted?

A. I recommend that the Michigan Public Service Commission require the Company, in its next distribution plan, to rigorously investigate the ability of its distribution system to handle higher levels of electric heating before significant capacity upgrades are needed.

Q. Are there other results you wish to highlight?

A. Yes. I would like to present a set of findings that Witness Graham Woolley's model produced using the eight scenario load profiles depicted in Exhibit CUB-25. We imported these profiles into his transformer aging model to estimate the degree to which each scenario impacts the expected life of typical distribution transformer equipment. These findings appear in the form of average transformer rating per customer in Table 2.

Incidentally, comparing the third and fourth scenarios in this table to Exhibit CUB-26 suggests that total annual load is not the primary driver of transformer degradation.

Table 2. Average Transformer Rating per Customer by Scenario

Scenario Name	Average Transformer Rating (kVA) per Customer
Baseline	1.724
44% BE	2.527
100% BE	4.451
44% BE_1 EV	2.986
44% BE_2 EV	3.459
44% BE_2 EV_5% PV	3.461
44% BE_2 EV_15% PV	3.408
44% BE_2 EV_25% PV	3.370

VI. RECOMMENDATIONS

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

A. On behalf of CUB, MEC, and NRDC, I recommend that the Commission:

(1) Direct the Company to conduct an analysis of its residential customers to determine whether treatment of single-family and multi-family customers in separate classes is justified.

(2) Direct the Company to provide a robustly time-differentiated rate structure that is available to electric heating customers and to treat these customers as a separate class for the purpose of COS analysis and rate design; and

(3) Direct the Company, in its next distribution planning case, to rigorously investigate the ability of its distribution system to handle potentially much higher levels of electric heating before significant capacity upgrades are needed.

Q. Does that complete your testimony?

A. Yes.

MS. ANDREWS: Thank you. Next, on behalf of the Citizens Utility Board of Michigan and the Michigan Environmental Council, I move for the admission of the Direct Testimony of Graham Woolley, which consists of a cover page, table of contents, and 20 pages of question and answers, together with motion to -- for the admission of Exhibits CUB-30 through CUB-33 into the record.

JUDGE WALLACE: Could you repeat the witness's name again?

MS. ANDREWS: Graham Woolley.

JUDGE WALLACE: All right. Is there any objection to the admission of the direct testimony of Mr. Woolley?

Hearing none, that testimony is bound in.

Is there any objection to the admission of Exhibits CUB-30 through CUB-33?

Hearing none, those exhibits are admitted.

(Testimony bound in.)

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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.	U-21534

DIRECT TESTIMONY OF GRAHAM G. WOOLLEY

ON BEHALF OF

CITIZENS UTILITY BOARD OF MICHIGAN AND MICHIGAN ENVIRONMENTAL COUNCIL

July 25, 2024

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I. INTRODUCTION & QUALIFICATIONS

Q. Please state for the record your name, position, and business address.

A. My name is Graham G. Woolley. I am a consultant at 5 Lakes Energy, a limited liability corporation, located at Suite 218, 220 MAC Avenue, East Lansing, Michigan 48823.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of Citizens Utility Board of Michigan (CUB) and Michigan Environmental Council (MEC).

Q. Please summarize your experience in the field of utility regulation.

A. I have worked for 5 Lakes Energy since December 2022. In this role, I have done extensive modeling to assess the value of low-carbon energy infrastructure projects and analyze the impact of weather on transformer aging to assist distribution system planning efforts. I also completed the MSU Institute for Public Utilities course on the Fundamentals of Utility Regulation (August 7-11, 2023). My work experience is summarized in my resume, provided as Exhibit CUB-30.

Q. Please summarize your expertise on the topics you plan to address.

A. In 2019 I completed an undergraduate degree in physics at UC Berkeley, with very high marks, where my research work included modeling of dark matter theories and experimental nuclear physics, and where my coursework included the physics of power systems. The topics I address in this testimony are straightforward applications of undergraduate-level electricity, magnetism and thermodynamics, in which I am fluent.

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

A. No.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit CUB-30:	Resume of Graham G. Woolley
Exhibit CUB-31:	Relationship between temperature and aging
Exhibit CUB-32:	Derivation of power losses within a transformer
Exhibit CUB-33:	Derivation of loss of life and expected lifetime

II. SUMMARY

Q. What topics are you addressing in your testimony?

A. On behalf of CUB and MEC, I am addressing the following topics:

- Transformer ratings and the physics of transformer aging; and
- Modeling transformer aging under real-world conditions

Q. What are your principal conclusions?

A. My principal conclusions are the following:

- Nominal transformer ratings don't capture the physics of transformer aging, and they should not be the sole basis for transformer sizing decisions;
- The physics of transformer aging lends itself to a more thorough and rigorous analysis that can be done with relatively simple modeling, which I demonstrate;
- Transformer aging occurs almost entirely in summer months (June through August), while almost none happens in the winter (December through February); and

- Increasing load during winter months is unlikely to compromise the health of existing transformers, which are typically sized to accommodate summer peaks.

III. TRANSFORMER RATINGS AND THE PHYSICS OF TRANSFORMER AGING

Q. What is the basis for transformer ratings?

A. Like any other electronic device, heat dissipates in a transformer when an electric current runs through it, causing its temperature to rise. Components in the transformer degrade faster at elevated temperatures, most importantly its insulation system. This thermal aging is a key determinant of the transformer's operational performance and longevity. Performance and safety become increasingly compromised as the insulation ages, eventually requiring repair or replacement. The transformer's nominal expected lifetime is predicated on the operational lifespan of its insulation, assuming operation at its nominal power rating. This rating is established under specific industry standard test conditions that typically include a constant load and an ideal ambient temperature—conditions that don't accurately reflect the fluctuating demands and environmental variables encountered in actual service. As such, while the nominal power rating serves as a benchmark for the transformer's capacity to handle power, it is an imperfect proxy for real-world operating scenarios.

Q. When power flow exceeds a transformer's rating, what is the effect on the transformer and its insulation aging rate?

A. Importantly, the transformer will accommodate power flows higher than the nominal rating; however, it does so at the cost of increased heat generation, which in turn accelerates the thermal aging of the transformer's insulation system. Like most chemical reactions, the

rate of aging is exponentially related to the temperature at which the reaction occurs. (Ex MEC-GGW-2) A useful rule of thumb is that the reaction rate doubles for every 10º C increase in reaction temperature. Consequently, as the operating temperature rises above the design limits, the aging process can accelerate significantly. However, the temperature (and hence the aging rate) is not determined by power flow alone. Other factors, such as the duration of overloading and the ambient temperature also play critical roles. In other words, while overload is a significant stressor, it is one of several variables that collectively influence the transformer's lifespan.

Q. What determines a transformer's temperature?

A. Transformer temperature changes based on how much heat is generated within it and how much is dissipated to the environment. This change can be described using a differential equation from thermodynamics, which tells us how temperature evolves over time. The key factors in this equation are the transformer's current temperature and the balance of heat within it over a given period; knowing both allows us to calculate the temperature at a later time. The balance of heat within the transformer can be resolved further into two components, namely the heat produced in the transformer during operation and the heat dissipated away to the surroundings. The change in temperature during a given period can be summarized by the following equation: $\mathbf{\Delta T = (Q_{in} - Q_{out}) / C}$. Here is the change in temperature, Q_{in} is the heat produced, Q_{out} is the heat dissipated to the surroundings, and C is the heat capacity of the transformer.[1]

[1] The bolded equation is one way of *defining* the heat capacity; it measures how much heat it takes to change an object's temperature. See https://en.wikipedia.org/wiki/Heat_capacity for more information.

Q. How does the operation of a transformer result in the production of heat within it?

A. In the equation describing temperature change, Q_{in} is the heat produced in the transformer over a given time frame, and it primarily consists of what we refer to as power losses, which are an inherent part of transformer operation. These power losses have two components: copper losses and core losses. Copper losses are named for the transformer's copper windings, in which, like with ordinary power lines, energy is lost due to the inherent electrical resistance of the material. Core losses are associated with the transformer's iron core and come from the magnetic interactions between the electric current and the core.[2] In both cases, the lost energy appears as heat within the transformer, increasing its internal temperature. This can be summarized by the following equation: $\mathbf{Q_{in} = E_{core} + E_{copper}}$. Although both core ($E_{core}$) and copper ($E_{copper}$) losses are conceptually straightforward, their mathematical expressions involve parameters that are not usually detailed on the transformer's specification sheet, such as magnetic flux density and electrical resistivity. Instead, manufacturers typically provide "losses at no load" and "losses at full load", which is enough for us to determine Q_{in} as a function of the load on the transformer. (Ex CUB-32).

Q. What are the variables that determine heat dissipation away from the transformer?

A. Heat dissipation away from a transformer, represented by Q_{out} in the temperature change equation, occurs in a very intuitive way: hot objects will transfer their heat to their cooler surroundings. The speed of this heat transfer hinges on three factors: the current temperature of the object in question, the temperature of the surroundings (also called the

[2] Core losses include hysteresis and eddy current losses. See https://evrpower.com/types-of-losses-and-efficiency-in-a-transformer/ for more information.

ambient temperature), and a parameter called the heat transfer coefficient, which describes how quickly heat can flow into or out of an object. This parameter is influenced by many variables, such as the geometry of the object, the specific heat transfer mechanism,[3] and the material properties of the object and the surroundings. In a transformer, the cooling system also plays a critical role. In summary: $\mathbf{Q_{out} = k(T_c - T_a)}$, where T_c is the object's current temperature, T_a is the current ambient temperature, and k is the overall heat transfer coefficient that takes into account all of the aforementioned variables. The equation for Q_{out} is a special case of Newton's Law of Cooling and underscores a key principle: the greater the difference between the transformer's temperature and the ambient temperature, the more quickly the transformer dissipates heat. This relationship highlights the importance of ambient temperature in determining a transformer's internal temperature, with lower ambient temperatures enhancing the transfer of heat away from the transformer.

Q. What is the relationship between a transformer's temperature and its aging rate?

A. I've already discussed all the factors that determine a transformer's temperature and the temperature's exponential relationship to the aging rate of the insulation system. This relationship is characterized by a number called the aging acceleration factor, or F_{AA}, which is given by the following expression, which is cited in Exhibit MEC-GGW-2: $\mathbf{F_{AA} = exp(A/T_{ref} - A/T)}$, where A is a parameter determined by the thermal properties of the transformer and T is the temperature within the transformer expressed in degrees Kelvin, also known as the absolute temperature. Here T_{ref} is a reference temperature given by the manufacturer and it usually has a value of 110 °C, or 383 Kelvin. An F_{AA} value greater

[3] See https://energyeducation.ca/encyclopedia/Heat_transfer_mechanisms.

than 1 indicates that the transformer will age faster than normal and shorten the expected life, while a value less than 1 lengthens it.

Q. What is the relationship between a transformer's aging rate and its expected lifetime?

A. The aging rate in each unit of time can be readily translated into a measure of lost life of the transformer, which is usually expressed as a percentage or as a fraction between 0 and 1 and is denoted by LoL. To calculate the actual expected lifetime, we would need to add together LoL values until they cumulatively add up to 1. In practice, to predict the expected life, we produce hourly LoL values for a single representative year to get a yearly LoL value, whose inverse is the expected lifetime expressed in years. (Ex MEC-GGW-4)

Q. What are the conditions that constitute a steady state in a transformer?

A. Steady-state refers to a situation where the transformer temperature doesn't change, or $\Delta T = 0$. Referring to the temperature change equation above, this is only possible when the heat production within the transformer is exactly balanced by the dissipation of heat to the surroundings, i.e. when $Q_{out} = Q_{in}$. Q_{out} is determined by the ambient temperature, while Q_{in} is determined by the magnitude of the power flow within a given period. In manufacturer testing, both ambient temperature and power flow are often held constant to establish a steady-state temperature and evaluate performance. In steady-state conditions, transformer aging and expected life are primarily influenced by the magnitude of the power flow and the ambient temperature.

Q. Under steady-state ambient temperature and power flow, what is the relationship between power flow and expected transformer life?

A. In steady-state conditions, higher power flow leads to higher internal temperature, mainly through increased copper losses, which accelerates aging and reduces expected lifetime.

Q. Under steady-state ambient temperature and power flow, what is the relationship between ambient temperature and expected transformer life?

A. In steady-state conditions, lower ambient temperature leads to lower transformer temperature and hence a slower aging rate, extending its expected lifetime.

Q. Under steady-state ambient temperature and power flow, and for fixed expected transformer life, what is the relationship between ambient temperature and power flow?

A. For a fixed expected transformer life, there is an inverse relationship between ambient temperature and power flow. This means that a transformer can accommodate higher loads during the winter than in the summer, thanks to lower ambient temperatures.

Q. When power flow varies with time in steady-state ambient temperature, what happens to transformer temperature and aging?

A. Under constant ambient temperature conditions, power flow and transformer aging vary in the same direction: higher power flow in one hour leads to higher temperature, and hence accelerated aging. Thus, all else being equal, hours with high load account for more transformer aging than hours with low load.

Q. When ambient temperature varies with time and power flow is steady-state, what happens to transformer temperature and aging?

A. Under constant power flow conditions, ambient temperature and transformer aging also vary in the same direction: higher ambient temperature in one hour leads to higher transformer temperature, and hence accelerated aging. Thus, all else being equal, warm hours account for more transformer aging than cold hours.

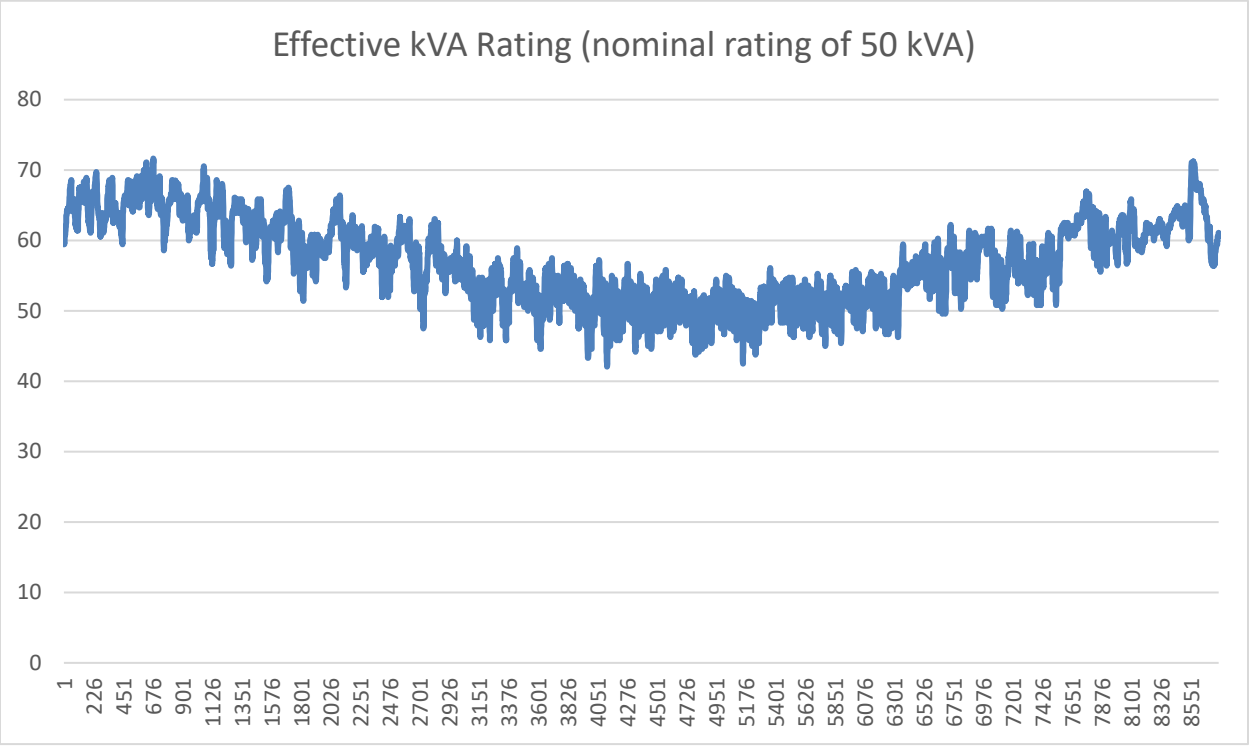
Q. Is it reasonable to think of a transformer as having a power flow rating that depends on ambient temperature?

A. The IEEE has a rule of thumb for estimating an "effective power flow rating" of a transformer based on ambient temperature.[4] In short, a lower ambient temperature yields a higher effective power flow rating. This heuristic is more accurate than using a single, fixed rating, but it has some drawbacks: it fails to capture the exponential relationship between a transformer's temperature and its aging rate and doesn't account for the time-dependent physics of transformer aging. To better capture these complexities, I created a weather-dependent transformer aging model that considers a time-varying 8760-hour annual profile of both ambient temperature and power flow. This model provides a comprehensive estimate of transformer loss of life throughout the year and allows us to quantify aging patterns on a time-of-day, seasonal, or annual basis.

[4] See Table 3 in Section 6.4 of the IEEE guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators, which can be found at https://ieeexplore.ieee.org/document/6166928.

Q. Does your model include the IEEE heuristic for effective rating as a function of ambient temperature?

A. Yes. While this is not the principal output of the model, it does provide a rough picture, given by this IEEE recommendation, of the transformer's effective rating. The chart below illustrates this heuristic for a transformer serving residential customers:



Qualitatively, we see that in winter months (December-February), the transformer can accommodate higher loads than in the summer months (June-August). There are daily fluctuations throughout the year as well, but the seasonality is important for the discussion in the following section, in which I quantify some of these trends.

Q. Is it reasonable to allocate costs for distribution system maintenance and upgrades based on peak loads?

A. No. Doing so fails to accurately account for what causes transformer aging. For example, residential peak loads may be quite high, but brief, due to demand for air conditioning, whereas commercial and industrial loads may be persistently high, leading to higher overall aging. In winter months, if a large portion of residential buildings have electrified their space heating requirements, peak loads may be quite high, but aging would be slowed by cold ambient temperatures. Rates paid by each customer class should reflect what they contribute to real transformer aging rather than peak demands. Our model provides a much more accurate picture of these costs.

IV. MODELING TRANSFORMER AGING UNDER REAL-WORLD CONDITIONS

Q. What data does your model need to calculate transformer aging?

A. It is, in practice, impossible to exactly solve the differential equations from thermodynamics that govern transformer aging due to the lack of high-resolution data. The model uses a standard numerical approach which applies the equations over discrete intervals. This method requires an 8760-hour profile for both the ambient temperature and the power flow through the transformer, representing an entire year's worth of hourly data.[5] (*footnote pointing to the LoL and F_{AA} equations, showing that the industry standard is to use discrete time intervals). Several manufacturer specifications are also necessary to fully capture the dynamics of transformer temperature: the model requires the mass of some of the transformer's components, its nominal expected lifetime, its nominal kVA rating, its

[5] Hourly intervals are the industry standard practice; more granular data is not usually available.

cooling system type, and the core and copper losses observed during manufacturer testing. These specifications give an adequate proxy for the physical characteristics relevant for this kind of thermal analysis on a transformer; they allow the model to calculate the loss of life (LoL) in each hour, providing a comprehensive view of the aging rate throughout the year.

Q. Please describe how your model calculates the aging rate and loss of life.

A. Detailed calculations can be seen in the logic of the model itself, which documents the relevant formulas extensively. A blank version of the model is found in the workpaper titled "Transformer Weather-Dependent Aging Model for DTE 2024 Rate Case.xlsb". To summarize: given the inputs listed above, the model calculates the transformer's heat capacity (C), and then for each hour it calculates the heat generated in the transformer (Q_{in}), the heat dissipated to the surroundings (Q_{out}), and the resulting change in transformer temperature (ΔT). This temperature change is used to update the transformer temperature from the previous hour to the current hour. To be conservative, the model adds 5 °C to the result, a buffer recommended by the IEEE,[6] to represent the so-called hottest spot temperature of the transformer, which in turn is used to calculate the aging acceleration factor and the loss of life in each hour. The hourly values are summed to an annual total, which represents an annual loss of life.

[6] See section 6.2 of https://ieeexplore.ieee.org/document/6166928.

Q. Does the temperature in one hour depend on the conditions of the previous hour?

A. Yes: the heat dissipated to the surroundings in one hour is proportional to the difference between the transformer's temperature and the ambient temperature in the previous hour. This is an effect called "hysteresis", where a system's behavior depends on its history.

Q. Does it matter what the model assumes for the temperature in the first hour?

A. The initial transformer temperature is not a significant factor in the outcome of the model calculations, which take place over an entire year. The hysteretic nature of heat dissipation is such that the transformer effectively erases any memory of its previous temperature after enough time has elapsed. In our model, given a load profile, starting temperatures of 1000 ^{o}C and 10 ^{o}C converge to nearly the same conditions after 24 hours. Since it makes a negligible difference where the model starts, we set the initial temperature to 20 ^{o}C.

Q. How does your model calculate the heat transfer coefficient of the transformer?

A. The heat transfer coefficient is the one variable that the model leaves free to calibrate itself to any transformer. Before we run the model with real-world conditions, we first run the model with an input of constant ambient temperature and constant load, with the magnitudes of each equal to the manufacturer's reference ambient temperature and the nominal kVA rating, respectively. These are the conditions that determine the transformer's expected lifetime. Thus, our initial run of the model should give us an expected lifetime that matches the number in the manufacturer specifications. If this is not the case, we tune the heat transfer coefficient to give us that result. Once the heat transfer coefficient is calibrated to match the manufacturer's specifications for expected life, we can then apply the model to real-world conditions.

Q. What scenarios are you considering for the subsequent analysis, and what are they meant to represent?

A. I constructed load profiles for three scenarios in the Company's transformer network: (1) a line transformer serving only residential customers, (2) a line transformer serving only secondary commercial customers, and (3) a representative substation transformer. To perform an analysis with this model, I needed to specify a few characteristics of the transformer in question, which I attempted to obtain through discovery. The Company provided requirements sheets for transformers in their network, but these are different from the specifications the model requires. We assumed a 50 kVA transformer for scenarios (1) and (2) and a 5 MVA transformer for scenario (3). Lacking the necessary specifications from the Company, we used manufacturer's specs through Larson Electronics as a proxy, which provide all the information we need to run the model. Details can be found in the following workpapers:

- Transformer Weather-Dependent Aging Model - Residential Line Transformer.xlsb (Scenario 1);
- Transformer Weather-Dependent Aging Model - Secondary Commercial Line Transformer.xlsb (Scenario 2);
- Transformer Weather-Dependent Aging Model – Substation Transformer.xlsb (Scenario 3).

Q. How did you construct the load profiles for these scenarios?

A. The construction of the load profile for each scenario is documented in the workpaper titled "dte_transformer_config.ipynb". In brief, I took the Company's rate-specific hourly loads from "U-21534 MNSCDE-10.15 - Part III Attachment 5 (28) COMPLETE_Updated

2022.xlsx", a copy of which I included as a workpaper, for 2022 and aggregated selected rates to separately represent all residential customers, all secondary commercial customers, and the system as a whole. I then scaled each profile to a magnitude meant to represent a single residential customer, a single secondary commercial customer, and a single substation transformer.

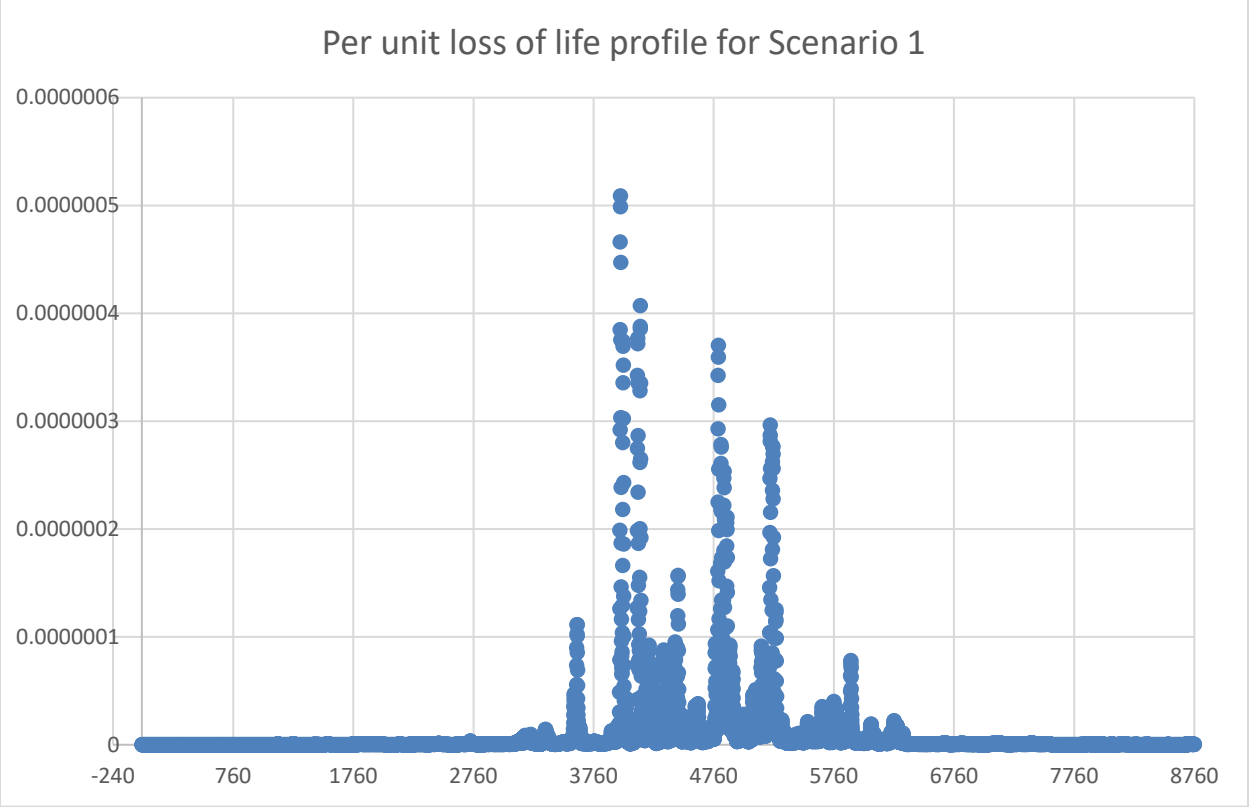
Q. Does the loss of life computed in your model match what the Company has observed in its service transformers?

A. It is unlikely that our model matches the Company's historical observations, for several reasons. First, a line transformer usually serves a mix of residential and commercial customers, while our load profiles represent one or the other. Second, the ideal input for the model is the transformer's hourly power flow. This data is unavailable, so we had to construct representative load profiles and scale them to the transformer level by choosing a "number of customers per transformer". This number is critically important because it affects the magnitude of the transformer load, but it is in practice very difficult to choose it correctly. Our approach was to apply a standard practice in which the transformer size is chosen so that its nominal capacity can accommodate the anticipated annual peak load. Third, we used specifications for models of transformers that may not reflect the real characteristics of the Company's transformers. Thus, our analysis likely does not represent the reality of most of the Company's service transformers, but our intention here is not to do a comprehensive aging analysis for the Company's network. The analysis that follows is necessarily qualitative and imprecise since we lack data on specific transformer loads and real transformer characteristics. Our scenarios are intended to demonstrate the

qualitative differences between different customer classes with respect to transformer aging and to illustrate how aging depends on more than peak loads.

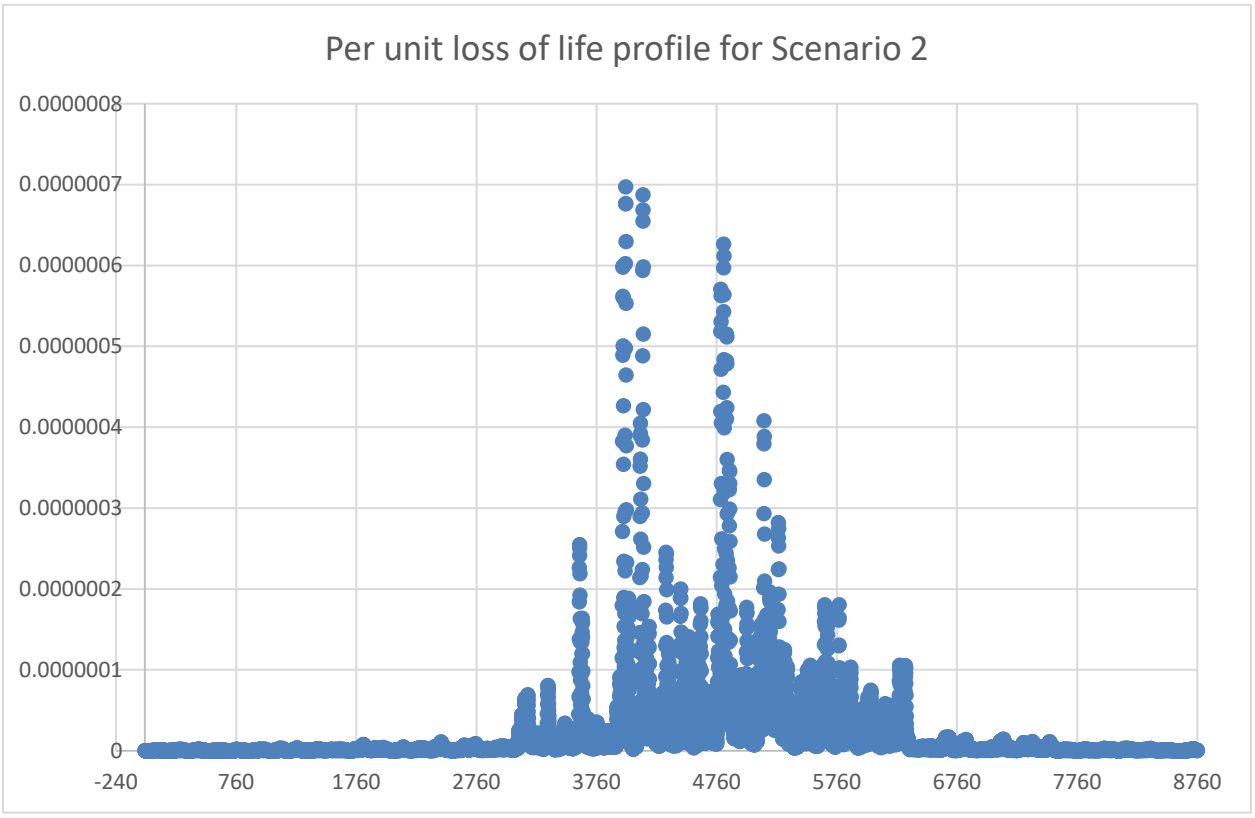
Q. For Scenario 1 (a transformer serving only customers with the Company's average residential load profile), what is the annual transformer aging profile?

A. The aging profile below is directly from the Scenario 1 workpaper.



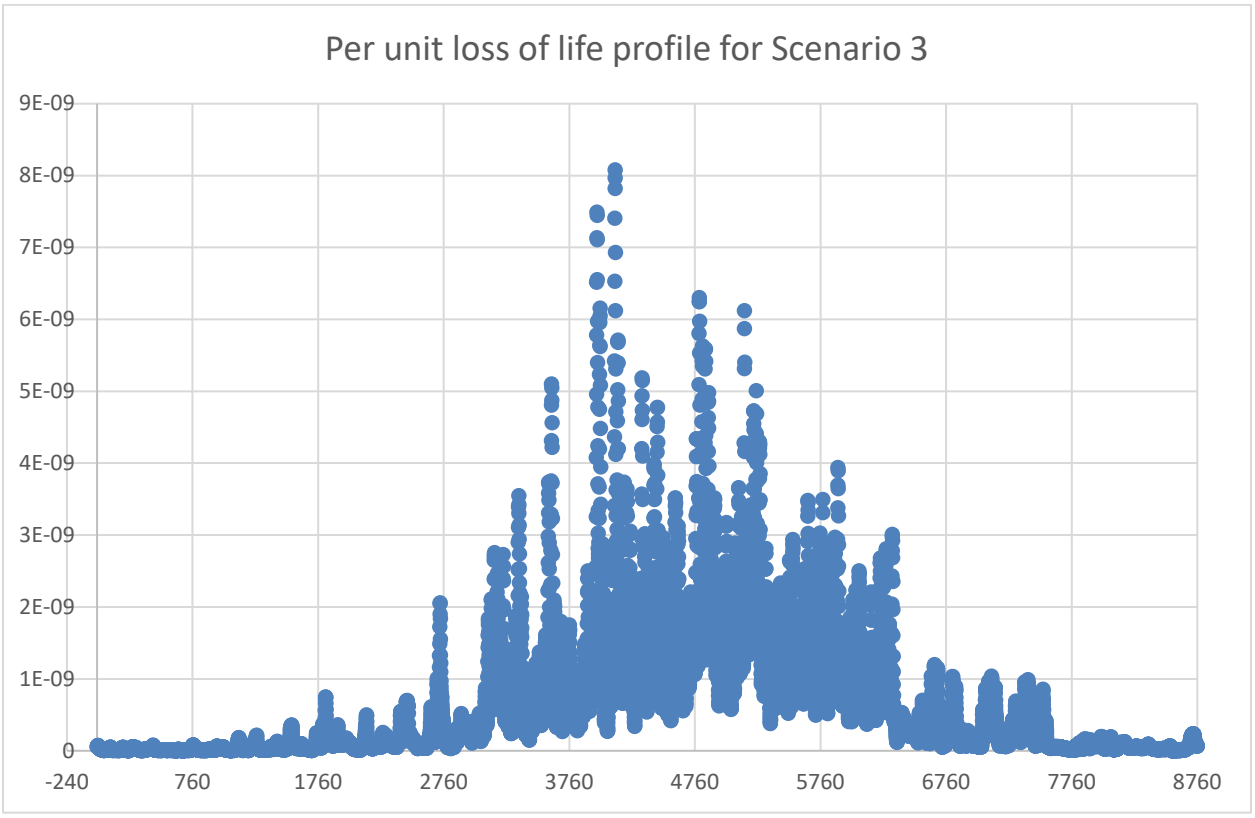
Q. For Scenario 2 (a transformer serving only customers with the Company's average secondary commercial load profile), what is the annual transformer aging profile?

A. The aging profile below is directly from the Scenario 2 workpaper.



Q. For Scenario 3 (a representative substation transformer serving a portion of the system load), what is the annual transformer aging profile?

A. The aging profile below is directly from the Scenario 3 workpaper.



Q. What qualitative conclusions should be drawn from the above profiles?

A. I want to highlight that in each of these scenarios, almost all the aging occurs during the summer, especially during the very warm hours of June through August. While this is attributable in part to increased electricity demand from air conditioning, the ambient temperature also plays a role, as I'll demonstrate.

Q. What are the key statistics to draw from each scenario?

A. The key statistics I want to highlight are summarized in the following table. Please note that I'm defining winter as December-February and summer as June-August.

Statistic	Scenario 1	Scenario 2	Scenario 3
Expected life / peak load (years per kW of peak hourly load)	304.7	123.3	123.4
Average load / peak load	0.3512	0.5292	0.5272
Fraction of annual aging occurring during summer months (June-August)	0.8859	0.8080	0.6551
Fraction of annual aging occurring during winter hours (December-February)	0.0035	0.0082	0.0128
Average load / average temperature during summer months (kW per degree Kelvin)	0.0749	0.0990	2.689
Average load / average temperature during winter months (kW per degree Kelvin)	0.0669	0.0979	2.557

Q. What conclusions can be made given the above statistics?

A. Several important points can be drawn from the table above:

1) The ratio of expected life to peak load demonstrates that peak loads are a poor proxy for transformer aging. While Scenario 2 has the same peak load as Scenario 1, the aging is significantly accelerated because loads are persistently high in Scenario 2, as evidenced by the higher ratio of average load to peak load.
2) In all scenarios, almost all aging occurs during the summer months, while almost none occurs in the winter. This observation highlights the critical point that transformer aging is significantly influenced by ambient temperatures.
3) In all scenarios, despite the average load to average temperature ratios being nearly the same for summer and winter months, the fraction of aging occurring in winter remains extremely low compared to summer. This indicates that higher ambient temperatures in the summer exacerbate aging effects even when the average load relative to temperature is similar. For instance, in Scenario 3, the average load to average temperature ratio during summer months is comparable to the same ratio

in the winter. However, the aging fraction during winter is negligible, highlighting a cold winter's protective effect on transformer longevity.

In conclusion, the predominant transformer aging during the summer can be attributed to the combined effect of higher loads and elevated ambient temperatures. Conversely, during the winter, the lower ambient temperatures significantly reduce aging, even if the loads are comparably high relative to temperatures. This supports the argument that winter months can accommodate higher loads without compromising transformer longevity.

V. CONCLUSIONS

Q. Please summarize the conclusions of the above discussion.

A. My analysis has shown the following:

(1) Nominal transformer ratings are an imperfect proxy for transformer aging;

(2) It is possible to do a more thorough and rigorous accounting of transformer aging by applying the first physical principles of transformer operation, if one has access to the relevant data;

(3) Transformer aging occurs primarily during the summer months; and

(4) The practice of sizing transformers for summer loads means that they can accommodate substantially higher winter loads without sacrificing transformer longevity.

Q. Do you have any recommendations for the Commission?

A. No. My testimony is intended as technical support for other witnesses on this topic.

Q. Does that complete your testimony?

A. Yes.

MS. ANDREWS: Next, on behalf of the Natural Resources Defense Council and the Michigan Environmental Council, I'd move for the admission of the Direct Testimony of Roger Colton, which consists of a cover page, table of contents, 55 pages of question and answers, and for the admission of Exhibit NRD-1.

JUDGE WALLACE: Is there any objection to binding in the direct testimony of Mr. Colton?

Hearing none, the testimony is bound in.

Is there any objection to the admission of Exhibit NRD-1?

Hearing none, that exhibit is admitted.

(Testimony bound in.)

- - -

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	U-21534

DIRECT TESTIMONY OF ROGER COLTON

ON BEHALF OF

NATURAL RESOURCES DEFENSE COUNCIL AND MICHIGAN ENVIRONMENTAL COUNCIL

July 25, 2024

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I. INTRODUCTION

Q. Pleast state your name and address.

A. My name is Roger Colton. My address is 34 Warwick Road, Belmont, Massachusetts.

Q. By whom are you employed and in what position?

A. I am owner of the firm of Fisher Sheehan & Colton, Public Finance and General Economics of Belmont, Massachusetts. In that capacity, I provide technical assistance to a variety of federal and state agencies, consumer organizations and public utilities on rate and customer service issues involving water/sewer, natural gas and electric utilities.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Natural Resources Defense Council (NRDC) and Michigan Environmental Council (MEC).

Q. Please describe your professional background.

A. I work primarily on low-income utility issues. This involves regulatory work on rate and customer service issues, as well as research into low-income usage, payment patterns, and affordability programs. At present, I am working on various projects in the states of Massachusetts, Connecticut, Maryland, Pennsylvania, Ohio, Michigan, Wisconsin, Illinois, Missouri, Oregon and Washington, as well as in the Canadian provinces of Nova Scotia and British Columbia. My clients include state agencies (e.g., Pennsylvania Office of Consumer Advocate, Maryland Office of People's Counsel, Connecticut Office of Consumers Counsel), federal agencies (e.g., the U.S. Department of Health and Human Services), community-based organizations (e.g., Cleveland Legal Aid Society, Legal Action of Chicago, Sierra Club), and public and private utilities (e.g., Toledo Water, BC

Hydro). Examples of my work include my current projects to assist the Connecticut Office of Consumers Counsel (OCC) in the annual review of the low-income affordability initiatives of that state's utilities by the Public Utilities Regulatory Authority. I am also assisting the Massachusetts Attorney General's Office (AGO) in the generic investigation by the Department of Public Utilities (DPU) into the design of low-income affordability programs. I am currently under contract to develop a universal service plan for British Columbia and recently completed the preparation of a universal service plan for Nova Scotia. In addition to state-specific and utility-specific work, I engage in national work throughout the United States and Canada. For example, I have recently completed a project with the Natural Resources Defense Council to develop a tool by which to assess the financial impact of differing types of low-income bill assistance. I continue to be "of counsel" to the National Coalition for Legislation on Affordable Water (NCLA-Water). A brief description of my professional background is provided in Exhibit NRD-1.

Q. Please describe your educational background.

A. After receiving my undergraduate degree in 1975 (Iowa State University), I obtained further training in both law and economics. I received my law degree in 1981 (University of Florida). I received my Master's Degree (Regulatory Economics) from the MacGregor School (Antioch University) in 1993.

Q. Have you ever published on public utility regulatory issues?

A. Yes. I have published three books and more than 80 articles in scholarly and trade journals, primarily on low-income utility and housing issues. I have published an equal number of technical reports for various clients on energy, water, telecommunications and other

associated low-income utility issues. A summary of my publications is included in Exhibit RDC-1.

Q. Have you ever testified before this or other utility commissions?

A. Yes. I have testified on multiple occasions before the Michigan Public Service Commission ("Commission" or "PSC") regarding both the natural gas and electric Energy Waste Reduction ("EWR") plans of DTE Energy and Consumers Energy as well as in a variety of rate cases. I have previously testified before the Commission in the following cases:

- Case U-18255 (DTE Electric Company's 2017 General Rate Case);
- Case U-18262 (DTE Electric Company's 2018–19 EWR Plan);
- Case U-20373 (DTE Electric Company's 2020–21 EWR Plan);
- Case U-20429 (DTE Gas Company's 2020–21 EWR Plan);
- Case U-20561 (DTE Electric Company's 2020 General Rate Case);
- Case U-20875 (Consumers Energy 2022 – 2023 EWR Plan);
- Case U-20876 (DTE Electric Company's 2022–23 EWR Plan);
- Case U-20881 (DTE Gas 2022-2023 EWR Plan); and
- Case U-21189 (Indiana Michigan Power Company IRP).

My testimony has specifically included testimony in various proceedings involving low-income program design and operation, along with various rate design issues as they affect low-income customers. Overall, I have testified in more than 340 judicial and regulatory proceedings in 43 states and various Canadian provinces on a wide range of utility issues. A list of the jurisdictions in which I have testified is listed in Exhibit NRD-1.

II. SUMMARY

Q. Please explain the purpose of your direct testimony.

A. The purpose of my Direct Testimony is to address the following topics:

- The affordability of DTE electric rates to low-income customers;
- The structure and operation of DTE's Residential Income Assistance Credits (RIA) and DTE's Low-Income Assistance (LIA) Bill Credits; and
- The structure and operation of DTE's Arrearage Management Program (AMP).

Q. Please summarize the recommendations you make throughout your testimony which follows.

A. Based on the data and analysis I present throughout my testimony, I recommend:

- I recommend that the RIA credit remain at $8.50 per month. However, I recommend that those credits be redirected to a different population. I recommend that the RIA program be restructured to provide assistance to customers establishing special needs when those customers have documented income not to exceed 250% of the Federal Poverty Level or 60% of the State Median Income, whichever is greater. Rather than funding these redirected benefits through new costs to ratepayers, this restructured program should be funded through dollars that are already planned to be directed to RIA recipients with income at or below 150% of Poverty Level.
- I recommend that DTE's outreach and intake procedures remain as they are. To the extent that a public assistance program would demonstrate an income-eligibility for the RIA, proof of participation in that assistance program should

be accepted as proof of eligibility for the RIA. To the extent that a household does not participate in such a public assistance program, the Company should accept documentation from one of its community-based intake organizations that the customer is income-eligible. It should not be difficult for DTE to identify customers with income up to 200% of the Poverty Level. DTE Electric's seasonal protections extend up to 200% of Poverty Level. DTE Electric has established procedures for identifying households with income up to 200% of Poverty. A household that has been so identified appears in the customer profile of the DTE Electric Customer Relational Management ("CRM") program. A customer who has been qualified for the seasonal protections should be found to have established "special needs" for purposes of the redirected RIA credits. Customers with incomes at or below 150% FPL and participating in the current RIA would be redirected to the LIA program.

- I recommend that DTE move away from offering a flat across-the-board bill credit through its LIA initiative. More specifically, I recommend that the LIA program be modified to adopt the following tiered bill credits: (1) income at 0 – 50% FPL: bill credit of $95/month; (2) income at 50 – 100% FPL: bill credit of $80/month; and (3) income at 100 – 150% FPL: bill credit of $45/month.

- I recommend that DTE be allowed to reconcile its actual LIA costs to its projected LIA costs on an annual basis. Whether those costs are under-recovered or over-recovered, the excess or deficit would be tracked by DTE as a regulatory asset to be included in rates in DTE's next base rate case. When included in rates, the projected costs, along with the over- or under-recovery, would be recovered in base rates as would any other DTE expense.

- I recommend that the Commission remove the cap on both the RIA and the LIA ceiling enrollment and allow the programs to achieve whatever participation is possible.

- I recommend that DTE expand its LIA program to provide for the enrollment of self-attested recipients of assistance through the federal Supplemental Nutrition Assistance Program (SNAP) (formerly known as Food Stamps). Additional programs, a determination of eligibility for which would also establish a household's low-income status, should be included, also, over time as the Commission determines which programs would serve the purpose of facilitating enrollment by eliminating administrative barriers to enrollment. For example, such programs might include, but not be limited to, Medicaid, LIHEAP, Free School Lunches, and the like.

- I recommend two modifications to the manner in which DTE grants its arrearage forgiveness credits. First, I recommend that rather than providing arrearage forgiveness credits only at three program points (the beginning of participation, the 12-month mark, the 24-month mark), program participants receive a pro rata forgiveness of their pre-program arrears for each complete bill payment they make over their 24-months of participation. In this fashion, the arrearage forgiveness program responds to complete bill payments by allowing program participants to see a continuing reduction in their pre-program arrearage balance. Second, I recommend that arrearage credits be provided for each complete payment, and that retroactive credits be provided when a previously missed payment is "cured" such that the bill balance is brought to $0.

- I recommend a tiering of arrearage forgiveness benefits. Even after providing the EIA credit, the customers in this lowest income range will have the most difficulty paying their bills in a complete fashion over a full 24-month period.

  This impact can be offset by recognizing the increased payment difficulty which even a modified LIA credit imposes on the lowest income participants. This recognition can, and should, be accomplished by allowing customers with income in this lowest income bracket (0 – 50% FPL) to earn their complete arrearage forgiveness over a 12-month period rather than a 24-month period. This tiering of forgiveness credits sends the message that the program recognizes the higher payment problems which remain, even after adopting a tiered LIA credit, but will thus reward full payment over a shorter period of time.

III. PART 1. THE AFFORDABILITY OF DTE ELECTRIC RATES

Q. Please explain the purpose of this section of your testimony.

A. In this section of my testimony, I examine the affordability of DTE electricity rates. First, I examine the particular importance of examining the affordability of electricity in this period of high inflation rates faced by customers. I explain how, and why, inflation has a particularly adverse impact on low-income customers. Second, I examine the growth in DTE electricity prices over time. Finally, I examine the affordability of DTE's existing

rates and the affordability of DTE rates as the Company proposes to increase them in this proceeding.

A. The Impact of Inflation on Low-Income Customers.

Q. Is there a particular concern about the impacts of higher DTE bills in today's economic environment?

A. Yes. Inflation in today's economic environment is disproportionately affecting lower-income households. Given the Commission's obligation to balance the interests of investors and ratepayers in setting a reasonable return on equity, the Commission should consider the greater adverse impacts that inflation has imposed on low-income ratepayers when setting rates.

Q. Please explain how inflation has a particularly adverse impact on lower income households.

A. The impact of inflation is felt most severely by low-income households. Research by the U.S. Department of Labor's Bureau of Labor Statistics, the agency that calculates and reports the "rate of inflation" (i.e., the Consumer Price Index [CPI]) each month, reports that "consumers with different incomes experience inflation quite differently."[1] According to this research, households earning lower incomes spend a higher share of their household budget on household necessities such as rent, food and medical care.

[1] Klick and Stockburger (December 2022). Spotlight on Statistics: Inflation Experiences for Lower and Higher Income Households, U.S. Department of Labor, Bureau of Labor Statistics, available at https://www.bls.gov/spotlight/2022/inflation-experiences-for-lower-and-higher-income-households/home.htm

Table 1. Household budget shares of expenditure items for lowest and highest income quartiles, 2017–2018[2]

Expenditure	Lowest Income Quartile	Highest Income Quartile
Rent (including owner's equivalent rent	34.93%	27.93%
Food at home	9.44%	6.58%
Medical care	8.36%	8.09%
Household utilities	4.36%	2.73%
Motor fuels	3.46%	3.42%
Motor vehicle operation	3.44%	3.40%
Telephone service	2.32%	2.00%

While low income households pay more of their budgeted income for this basket of essential goods, it is also important to note that the BLS researchers found that "prices for motor fuel, medical care, fuel and utilities, and shelter rose faster than the overall average. . ."[3] Thus, "[b]ecause the lowest income households dedicate more of their spending on these categories," the BLS researchers found, "their overall inflation rates grew faster than the highest income households."

[2] *Id.*

[3] *Id.*

Table 2. Average price change by item, 2005–2020
(starred items defined by BLS to be household necessities)

Item	2005–2020 average 12-month change (%)
Tuition, other school fees, and childcare	4.03
Motor Fuel*	3.45
Medical Care*	3.28
Rent*	3.06
Food away from home	2.86
Fuel and utilities*	2.71
All items	2.00
Food at home*	1.89
Lodging away from home	1.16
Recreation	0.74
New and used motor vehicles	0.43
Apparel	-0.10
Telephone services*	-0.20

The Federal Reserve Bank of Dallas similarly found that

> Families have grappled with surging prices over the past 18 months, as the cost of meeting basic needs rose. Consumer prices were 7.1 percent higher in November 2022 than one year earlier.
>
> Although inflation may have peaked, prices remain elevated, with food costs up 10.6 percent, gasoline rising 10.1 percent, rent increasing 7.9 percent and medical care services up 4.4 percent.

> Drawing upon recent household survey data, we show that high inflation is disproportionately hurting low-income households, including Black and Hispanic households and renters.[4]

Q. Do low-income households have the same tools to adapt to higher prices, resulting from inflation, as non-low-income households?

A. No. The Federal Reserve researchers found that the "stress" being placed on households by high inflation is much greater for low-income households. They explained:

> Prior research suggests that inflation hits low-income households hardest for several reasons. They spend more of their income on necessities such as food, gas and rent—categories with greater-than-average inflation rates—leaving few ways to reduce spending. When prices rise, middle-income households may react by consuming cheaper goods and buying more generic brands. Low-income households do not have the same flexibility; in many cases, they are already consuming the cheapest products.
>
> Additionally, many low-income households lack the ability of higher-income households to stock up when prices are discounted, buy in bulk and save, delay purchases if there is an opportunity to save in the future or buy more cheaply online. Low-income households are also likely to have smaller cash buffers to tide them over a period of high inflation.
>
> The recent Household Pulse Survey data confirm these tendencies. Households with incomes ranging from $25,000 to $35,000 in 2021 were about 19.3 percentage points more likely to be very stressed by inflation than households with incomes in the $75,000 to $100,000 range.

The data is clear and it is consistent. Lower income families expend a greater share of their income on necessities (which tend to have higher inflation rates); have smaller financial cushions to mitigate the impact of inflation; and may have less of an ability to switch to

[4] Jayashankar and Murphy (January 2023). High inflation disproportionately hurts low-income households, Federal Reserve Bank of Dallas, available at https://www.dallasfed.org/research/economics/2023/0110#:~:text=Low%2Dincome%20households%20most%20stressed,few%20ways%20to%20reduce%20spending%20.

lower-priced alternatives. As Lael Brainard, a member of the Board of Governors of the Federal Reserve System, concluded, "All Americans are confronting higher prices, but the burden is particularly great for households with more limited resources."[5]

Q. What do you conclude?

A. The Commission is obligated to balance the interests of investors and ratepayers in setting reasonable rates. That balancing might occur in setting a return on equity. It should also occur in deciding upon rate design issues involving the fixed monthly customer charge and upon other issues. In so doing, the Commission should consider not merely the affordability impacts of DTE's request for higher rates, but should consider, also, the greater adverse impacts that inflation has imposed on low-income ratepayers as I have discussed above.

B. The Growth in DTE Electricity Rates Over Time.

Q. Have you examined the growth in DTE Electric rates over time?

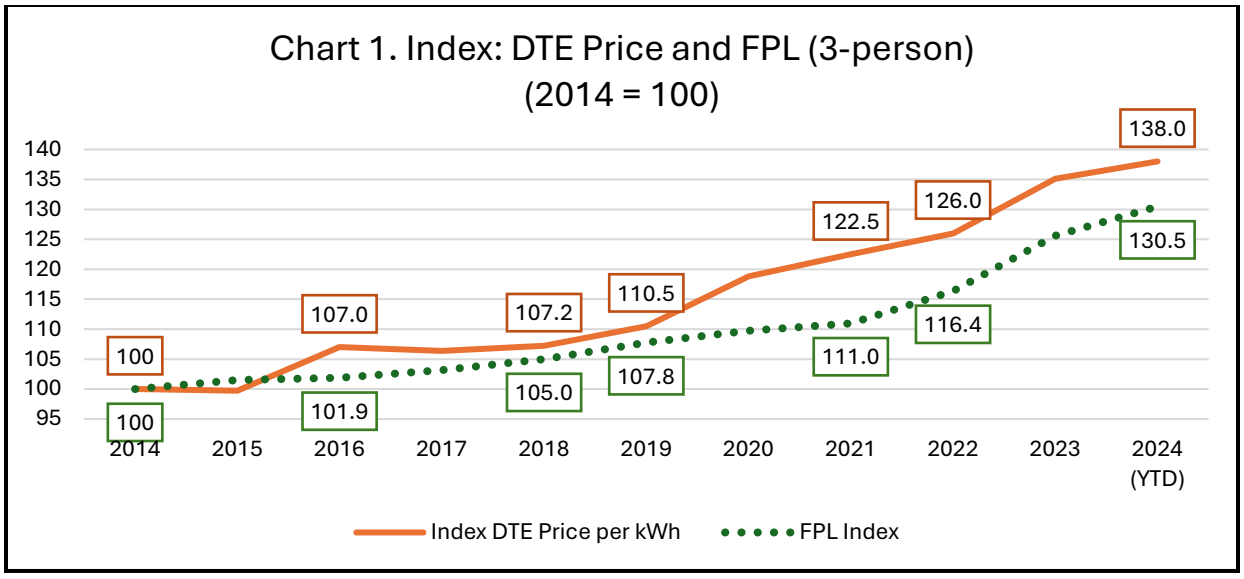
A. Yes. Using the data which DTE files with the federal Energy Information Administration (EIA) each year in its EIA Form 861,[6] I examined the price per kWh charged to residential customers for the years 2014 through 2024 (YTD-April). I examined the growth by setting the 2014 price equal to 100. Each subsequent year shows the movement in price relative to 2014.[7] As can be seen, after three years of relative stability in electricity prices (2016 –

[5] Brainard (April 2022). Variations in the inflation experiences of households, available at https://www.federalreserve.gov/newsevents/speech/brainard20220405a.htm.

[6] Available at https://www.eia.gov/electricity/data/eia861/.

[7] This is the same methodology used by the U.S. Department of Labor Statistics in showing the Consumer Price Index (i.e., rate of inflation).

2018), DTE's electricity prices have seen a sharp increase through 2024 (YTD-April). From 2014 through 2024, DTE's electricity prices have grown by nearly 40%. In contrast, over the same time period, the Federal Poverty Level for a 3-person household increased by only 30%. While the growth in DTE electricity rates only slightly exceeded the growth in the FPL through 2019, a more substantial gap appeared from 2020 through 2024.



Q. What is the significance of this growth in the gap between federal poverty level and DTE's electricity prices?

A. Within the low-income population, high energy prices create a competition between a household's ability to pay their home energy bill and their ability to pay other essential life expenses. The escalation of DTE's electricity prices at a rate sharply greater than the escalation of incomes not only exacerbates that competition, but makes it less likely that DTE bills can and will be paid on a sustainable basis. The most recent (2020) Residential Energy Consumption Survey (RECS) by the U.S. Department of Energy's Energy

Information Administration (DOE/EIA)[8] documents these results. The Table below shows that as incomes decline, the extent of "household energy insecurity" increases.

Table 3. Household Energy Insecurity 2020
(2020 RECS, Table HC11.1)

2020 annual household income	Total U.S.	Any household energy insecurity	Reducing or forgoing food or medicine to pay energy costs	Leaving home at unhealthy temperature	Receiving disconnect or delivery stop notice	Unable to use heating equipment	Unable to use air-conditioning equipment
Less than $5,000	100%	58%	47%	25%	27%	11%	12%
$5,000 to $9,999	100%	56%	47%	21%	19%	9%	8%
$10,000 to $19,999	100%	47%	38%	21%	18%	8%	9%
$20,000 to $39,999	100%	40%	31%	15%	14%	6%	8%
$40,000 to $59,999	100%	29%	22%	9%	11%	4%	6%
$60,000 to $99,999	100%	20%	13%	6%	7%	2%	3%
$100,000 to $149,999	100%	11%	6%	4%	4%	1%	2%
$150,000 or more	100%	7%	3%	3%	2%	1%	1%

Q. Do you have reason to believe that these "energy insecurities" exist in the DTE service territory as well?

A. Yes. The U.S. Census Bureau publishes a periodic "PULSE Survey" examining in relevant part the difficulties, if any, that households have in paying their normal household expenses "in the last seven days." The most recent PULSE Survey data release was for the period April 30 through May 27, 2024.[9] While the PULSE Survey does not report data by utility service territory, it does provide state-specific data, including data for Michigan. The Michigan data is set forth in the Table below. Several observations are important. First,

[8] Available at https://www.eia.gov/consumption/residential/data/2020/#household.

[9] Available at https://www.census.gov/data/tables/2024/demo/hhp/cycle05.html.

nearly three-fifths (59.6%) of households with income less than $25,000 reported finding it either "somewhat difficult" or "very difficult" to pay for usual household expenses in the last seven days. More than one-quarter (27%) of households with income less than $25,000, and nearly one-quarter (24.1%) of households with income between $25,000 and $35,000, found it "very difficult" to pay their usual household expenses. A significant drop in the percentage of households finding it "very difficult" occurs for households with income exceeding $35,000, just as a significant increase in the percentage of households finding it "not at all difficult" occurs for households with income greater than $25,000.

Table 4. Difficulty in paying for usual household expenses in the last 7 days (Michigan) (April 30 – May 27, 2024)

	Not at all difficult	A little difficult	Somewhat difficult	Very difficult	Total
Less than $25,000	17.7%	22.7%	32.6%	27.0%	100.0%
$25,000 - $34,999	31.5%	25.6%	18.8%	24.1%	100.0%
$35,000 - $49,999	22.2%	31.9%	29.7%	16.2%	100.0%
$50,000 - $74,999	32.2%	29.0%	20.4%	18.5%	100.0%
$75,000 - $99,999	38.2%	24.8%	20.7%	16.2%	100.0%
$100,000 - $149,999	49.1%	28.3%	16.5%	6.2%	100.0%
$150,000 - $199,999	65.7%	21.6%	10.5%	1.2%	99.0%
$200,000 and above	79.3%	15.2%	5.5%	---	100.0%

Given this very recent Michigan-specific data, and the assumption that DTE electricity bills are considered "usual household expenses," it is evident that the "home energy insecurities" reported by the RECS as I discuss above exist today in the DTE service territory.

C. The Affordability of Existing and Proposed Rates.

Q. Please explain the purpose of this section of your testimony.

A. In this section of my testimony, I examine the impact which DTE's proposed electricity rate increase in this proceeding will have on the affordability of bills to low-income customers. I begin with an examination of electricity burdens at different annual incomes, in tiers ranging from "less than $10,000" up to "$35,000 to $39,999." The impact of DTE's rate increase proposed in this proceeding is set forth in the Table below. As can be seen, under both existing and proposed rates, DTE electricity bills are unaffordable (using a 4% burden as the demarcation of electricity affordability)[10] for households with income less than $35,000.[11] For households with income in the range of $35,000 to $39,999, while DTE's bills were marginally affordable at existing rates, they become marginally unaffordable at DTE's proposed rates.

For households in the two highest income ranges, I then separately calculated the burdens *at* the lowest point in the range and *at* the highest point in the range. At existing rates, in other words, the DTE burdens range from 4.7% to 4.0% for households with income in the

[10] It is commonly accepted that a reasonable demarcation of "affordability" for *total* home energy is 6% of income. When a household is facing a single fuel (electricity, natural gas), however, that 6% is needs to be allocated between the two fuels. Two alternative allocations are reasonable: (1) simply to split the 6% half-and-half and allocate 3% to each; or (2) to allocate 4% to electricity and 2% to natural gas. Each of these decisions has a reasonable basis. Because the Department of Energy's Residential Energy Consumption Survey appear to document that electricity consumes a somewhat higher portion of a household's home energy expenditures, I tend to recommend a 4%/2% split. I would not, however, "argue" should the Commission decide, for simplicity's sake, to allocate the total home energy burden 50-50, and adopt an affordable electricity burden of 3%. My objection extends only to those who might assert that the allocation occur at a precision incorporating tenths of one percent (e.g., 3.8% vs. 2.2%). That allocation implies a precision in the allocation that simply does not exist.

[11] Note that I use the mid-point of each range for the calculation of the DTE electricity burden.

range of $30,000 to $34,999 (with a mid-point of 4.4%). The DTE burdens range from 4.0% to 3.5% (with a mid-point of 3.8%) for households with income in the range of $35,000 to $39,999. In contrast, at proposed rates, the DTE electricity burdens range from 4.4% to 5.2% for households with income in the range of $30,000 to $34,999 (with a mid-point of 4.8%), while they range from 4.4% to 3.9% for households with income in the range of $35,000 to $39,999 (with a mid-point of 4.1%).

Table 5. DTE Electricity Burdens by Income Range ($0 to $40,000) (at Existing Rates and at Proposed Rates) (bills at 600 kWh/month)

	Existing Rates		Proposed Rates	
	Monthly Bill at Existing Rates[12]	Burden Given Bills at Existing Rates[13]	Monthly Bill at Proposed Rates[14]	Burden Given Bills at Proposed Rates[15]
Total: Less than $10,000	$117.96	28.3%	$129.08	31.0%
Total: $10,000 to $14,999	$117.96	11.3%	$129.08	12.4%
Total: $15,000 to $19,999	$117.96	8.1%	$129.08	8.9%
Total: $20,000 to $24,999	$117.96	6.3%	$129.08	6.9%
Total: $25,000 to $29,999	$117.96	5.1%	$129.08	5.6%
Total: $30,000 to $34,999	$117.96	4.4%	$129.08	4.8%
Total: $35,000 to $39,999	$117.96	3.8%	$129.08	4.1%
At $30,000	$117.96	4.7%	$129.08	5.2%
At $35,000	$117.96	4.0%	$129.08	4.4%
At $40,000	$117.96	3.5%	$129.08	3.9%

[12] DTE Filing, Attachment 3.

[13] Monthly bill at existing rates as reported by DTE in its Filing (Attachment 3) annualized by multiplying by 12 months.

[14] *Id.*

[15] Monthly bill at proposed rates as reported by DTE in its Filing (Attachment 3) annualized by multiplying by 12 months.

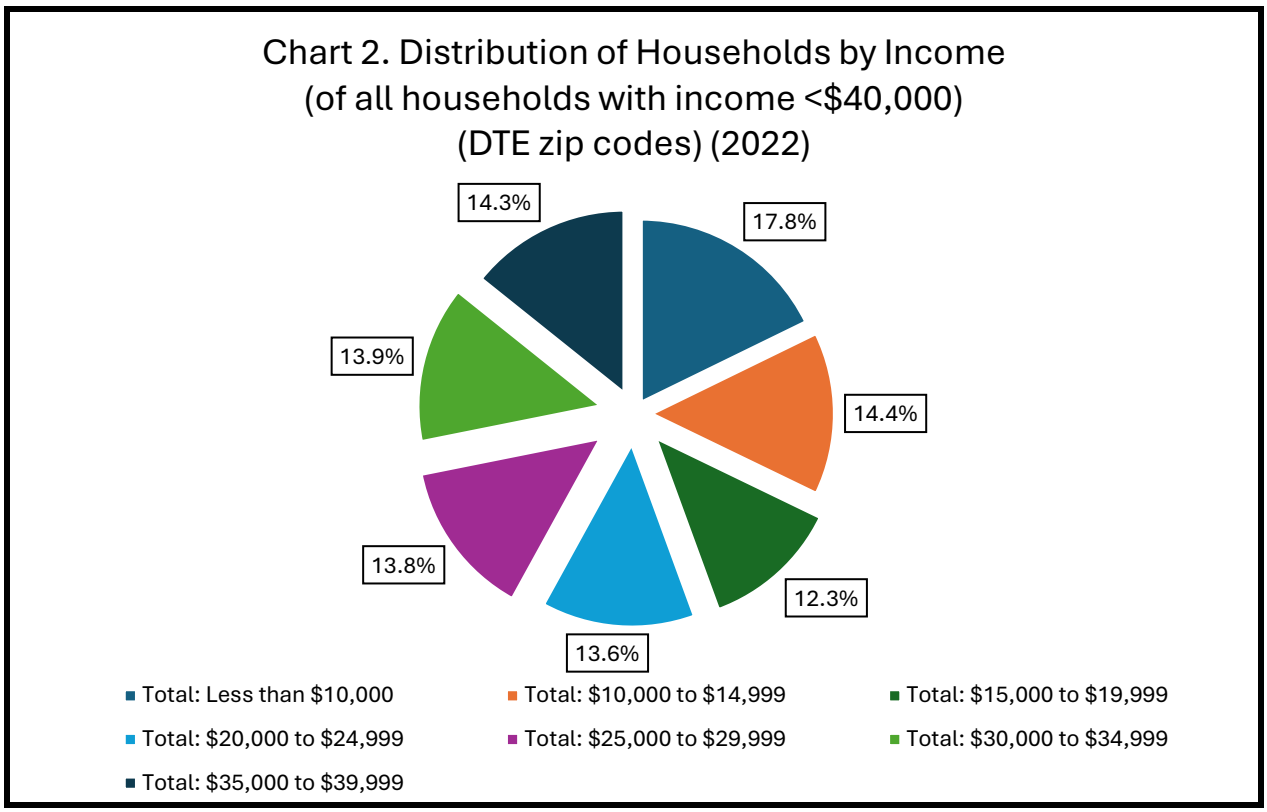
Due to the nature of the calculation, in other words, within each income range, there is a variation in DTE burdens from the burden at the mid-point depending on whether the household is at the "top" or at the "bottom" of the range.

Q. Why are these burdens significant for this proceeding involving DTE Electric rates?

A. The burdens set forth in the Table above are significant for this proceeding in two respects. First, there is a substantial range of unaffordability from the lowest incomes to the higher incomes within a low-income population. Because of this variation, I will further address the need to provide "tiered" benefits in my testimony below.

Second, the burdens are significant in that there are substantial numbers of households in the DTE service territory which live with incomes in the ranges I report in Table 5 above. In the zip codes comprising the DTE service territory, there were a total of 819,913 households living with income at or below $40,000. The Chart below shows the distribution of those households at the differing income ranges.

The Chart shows that nearly 20% of the households with income less than $40,000 in fact have income less than $10,000. Indeed, the population with income less than $10,000 is the biggest sub-group of the total population with income less than $40,000. Otherwise, the other ranges of income are reasonably closely distributed (with between 12% and 14% of households in each income range).



The first lesson to be learned from the Chart above is not only that the DTE customers experience unaffordable burdens in each income range, but also that there are substantial numbers of customers at each income range.

Q. Have you found the same results through any other analysis?

A. Yes. In my second inquiry, I consider the DTE burdens at existing and proposed rates disaggregated by ranges of Federal Poverty Level (FPL) rather than by ranges of dollars of income. FPL determines the low-income status of a household taking into account both annual income and household size. In 2024, for example, while 100% of FPL is $15,060 for a one-person household, it is $25,820 for a three-person household. Table 6 shows the same results as I found above. First, there is substantial unaffordability in the DTE service territory. Second, the difference in unaffordability is substantial as between the lowest income households (0 – 50% FPL) and the higher income households (100-200% FPL;

200-300% FPL). Third, the increased rates proposed by DTE in this proceeding will have a noticeable impact on burdens becoming even more unaffordable than they already are. Indeed, for households falling in the income range of 150% to 200% FPL, the rate increases proposed in this proceeding (at the mid-point of that income range) are what finally drives DTE electricity burdens to the level of being *at* the income mid-point, or *above* the income mid-point (at higher parts of this income range), an unaffordable burden of 4% of income.

Table 6. DTE Electricity Burdens at Existing and Proposed Rates
(by range of 2024 Federal Poverty Level)

	Existing Rates		Proposed Rates	
	Bill at Existing Rates[16]	Burden at Existing Rates	Bill at Proposed Rates[17]	Burden at Proposed Rates
0-50 FPL	$1,416	15.5%	$1,549	17.0%
50-75 FPL	$1,416	9.9%	$1,549	10.9%
75-100 FPL	$1,416	7.1%	$1,549	7.8%
100-125 FPL	$1,416	5.5%	$1,549	6.0%
125-150 FPL	$1,416	4.5%	$1,549	4.9%
150-200 FPL	$1,416	3.5%	$1,549	3.9%
200-300 FPL	$1,416	2.5%	$1,549	2.7%

As I note above, in my testimony below, I will recommend a remedy for the wide variance in burdens between the lower and upper tiers of low-income status in the DTE service territory.

[16] $117.96/month x 12 months.

[17] $129.08/month x 12 months.

D. Estimated vs. Known Low-Income Customers.

Q. Please explain why DTE's offer of its low-income assistance programs does not resolve the issues you identify above.

A. Even if I limit program participation to customers with income at or below 200% of FPL, I find that DTE programs reach only a fraction of its potentially eligible program participants. Based on 2022 Census data (the most recent available), I find that 26.1% of the population age 18 or older in DTE's zip codes have income at or below 200% of FPL. Applying that to DTE's average 2024 residential customer base (January through April) (2,064,746), as reported by the Company in its EIA Form 861M, DTE would have nearly 540,000 customers with income at or below 200% FPL (2,064,746 x 0.261 = 538,899). In contrast, the sum of participants in DTE's RIA and LSP low-income discount programs reaches only a fraction of that estimated low-income customer population.

Q. Doesn't the Federal LIHEAP program resolve much of the affordability problem that you have identified?

A. The existence of LIHEAP does not resolve the affordability problems that I identified above for three reasons. First, while Michigan reports that its LIHEAP program enrolls 90% of its state-income eligible population (431,842 of 481,913), most of the State's LIHEAP benefits are *not* devoted to assistance provided for *current* bills. Instead, according to data published by the National Energy and Utility Affordability Coalition (NEUAC),[18] of Michigan's 2023 LIHEAP appropriation of $287,098,293, the state distributed $172,524,560 (60%) in *crisis* assistance. Indeed, NEUAC reports that

[18] NEUAC is a a broad-based national coalition of stakeholders advocating for programs to assist vulnerable households meet their home energy needs.

Michigan used only $48,349,580 of LIHEAP benefits (17%) as assistance paid to offset current monthly bills. As such, Michigan LIHEAP dollars are not generally being used to reduce bills as a percentage of income.

Second, due to reduced Congressional appropriations, LIHEAP funding to Michigan (as with all other states) saw substantial reductions in 2023 (which reductions carried over to 2024). While Michigan received $419 million in LIHEAP funding in FY2021, and $406 million in FY2022, that funding was reduced to $287 million in FY2023.

Finally, and perhaps most significantly, neither DTE (nor the Commission) may reduce the level of utility discounts because of the availability of LIHEAP. The federal LIHEAP statute is quite explicit in this regard. The statute states that "the amount of any home energy assistance payments or allowances provided directly to, or indirectly for the benefit of, an eligible household under this title shall not be considered income or resources of such household (or any member thereof) for any purpose under any Federal or State law. . ."[19] Moreover, the federal LIHEAP office has found that using the existence of a LIHEAP grant as the basis to reduce the level of a discount offered to low-income households has the inappropriate impact of redirecting that grant away from benefitting the recipient to the benefit of other utility ratepayers.

Whether one agrees or disagrees with the impact of the federal LIHEAP statute on program design is not now an issue presented by DTE. Nonetheless, the lesson to be learned here

[19] 42 U.S.C. section 8623(f)(1).

is that LIHEAP benefits may not be considered by the Commission in deciding upon the structure and operation of DTE's low-income discounts.

Q. Is the affordability analysis you present above applicable to any other aspect of this DTE rate proceeding?

A. Yes. A consideration of affordability is a critical task to undertake within the structure of any utility rate case. As bills become increasingly unaffordable, the payment difficulties of those customers who face unaffordability become increasingly substantial as well. One impact of the unaffordability I identify is its impact on the operating costs (e.g., collection costs, working capital, uncollectible expenses) that are then normalized and passed on to other ratepayers. Also, DTE's proposals, such as increasing the residential customer charge, have disproportionate adverse effects on low-income customers who already are facing substantial unaffordability.

In addition, establishing a Return on Equity (ROE) is fundamentally predicated on balancing customer and investor interests. It is necessary for the Commission to understand the customer interests in order to appropriately balance them against the competing investor interests. The obligation of the Commission in deciding on the appropriate ROE and the reasonable mix of debt and equity securities should balance customer and investor interests. (*FPC v. Natural Gas Pipeline Co.*, 315 U.S. 575, 606-607 - 608). Indeed, of the customer issues that are important drivers of the just and reasonable ROE determination, one of the most significant is the concern about affordability. If a sizable portion of customers cannot afford to pay the rates imposed by the Commission, the Commission can hardly be said to have approved just and reasonable rates. In addition, as DTE adds more and more expensive plant, this increases rates, which may in turn put

downward pressure on the just and reasonable ROE not for financial reasons, but because of affordability concerns.

In sum, the concerns I identify with respect to the unaffordability of DTE rates can (and should) be considered in this rate case even outside the consideration of the specific proposals I advance with respect to specific low-income initiatives.

IV. PART 2. THE STRUCTURE AND OPERATION OF DTE'S RATE DISCOUNTS

Q. Please explain the purpose of this section of your testimony.

A. In this section of my testimony, I review the structure and operation of the rate discounts which DTE currently provides to low-income customers. The two discounts that I examine will include DTE's Residential Income Assistance Credits (RIA) and DTE's Low-Income Assistance (LIA) Bill Credits.

A. The Structure and Operation of the RIA Bill Credits.

Q. Please describe your understanding of the Residential Income Assistance Credits (RIA).

A. My understanding of the Residential Income Assistance Credits (RIA) is based on a reading of the testimony of DTE witness Jason Sparks in this proceeding. According to Mr. Sparks, the RIA credit offers low-income electric customers an $8.50 per month credit on their bill. To be eligible, the total household income cannot exceed 150% FPL, as verified by an authorized State or Federal agency. The credit is renewed annually based on the eligibility requirements. Customers may not receive both an electric RIA and electric LIA credit at the same time. Witness Sparks continued on to state that "[c]ustomers who receive energy assistance in the form of a Home Heating Credit (HHC), State Emergency Relief (SER),

or one time assistance are automatically enrolled to receive the RIA credit."[20] Sparks testified that "Over 160,000 unique electric customers received the RIA credit in 2023 with an annual monthly average of 75,522."[21] He said "In the projected test year, the Company is forecasting the RIA credit enrollment monthly average of 83,000 customers."[22]

Q. Have you had occasion to examine what impact receipt of an RIA credit has on low-income electric bill burdens for DTE's low-income customers?

A. Yes. The results of my examination of how the provision of RIA credits to customers with income at or below 150% of Federal Poverty Level (FPL) are set forth in Table 7 below. The second column of data presents bill burdens at the rates proposed by DTE in this proceeding with customers *not* having received an RIA credit. The fourth column of data presents bill burdens at the rates proposed by DTE in this proceeding *after* receipt of an RIA bill credit.

As can be seen, the RIA bill credit has a minimal impact on improving the affordability of electric bills for DTE's RIA participants. At the lowest FPL range, bill burdens remain nearly four times higher than an affordable electric burden of 4% of income (15.9%). At incomes of between 50% and 75% FPL, bill burdens are more than two-and-a-half times higher than the affordable level. Even at the higher income range within this population of customers with annual income at or below 150% of FPL, bill burdens *after receiving the bill credit* remain at unaffordable levels. At the bottom of this income range, bill burdens

[20] Direct Testimony of Jason E. Sparks, at 15.

[21] *Id*., at 16.

[22] *Id*.

would substantially exceed the 4% demarcation of affordability, while at the top of the range, burdens would more closely approach the 4% marker of affordability.

Table 7. Bill Burdens At Proposed DTE Rates Before and After Receiving an RIA Credit By Federal Poverty Level

	Without RIA Credit			With RIA Credit	
Federal Poverty Level	Bill without RIA[23]	Bill Burden w/o RIA	Federal Poverty Level	Bill with RIA[24]	Bill Burden w/ RIA
0 – 50% FPL	$1,549	17.0%	0 – 50% FPL	$1,447	15.9%
50 – 75% FPL	$1,549	10.9%	50 – 75% FPL	$1,447	10.2%
75 – 100% FPL	$1,549	7.8%	75 – 100% FPL	$1,447	7.3%
100 – 125% FPL	$1,549	6.0%	100 – 125% FPL	$1,447	5.6%
125 – 150% FPL	$1,549	4.9%	125 – 150% FPL	$1,447	4.6%

It is evident from the data above that the RIA is an ineffective mechanism through which to distribute affordability assistance to customers with income at or below 150% of FPL. Customers who have difficulty paying their bills having not received the RIA credit are likely to continue to have difficulty paying their bills after receiving the RIA.

Q. What do you recommend for the RIA Credit Program?

A. I recommend that the RIA credit remain at $8.50 per month. However, I recommend that those credits be redirected to a different population. I recommend that the RIA program be restructured to provide assistance to customers establishing special needs when those customers have documented income not to exceed 250% of the Federal Poverty Level or 60% of the State Median Income, whichever is greater. Rather than funding these redirected

[23] $129.08/month x 12 months.

[24] $1,549 – ($8.50/month x 12 months).

benefits through new costs to ratepayers, this restructured program should be funded through dollars that are already planned to be directed to RIA recipients with income at or below 150% of Poverty Level.

This concern for customers with income up to 60% of State Median is not unusual. Pursuant to the federal LIHEAP statute, the allowable maximum income eligibility for LIHEAP is set at the greater of 150% of FPL or 60% of State Median Income.

Q. Have you compared 60% of state median income to the poverty level in Michigan?

A. Yes. A comparison of 60% of State Median Income for Michigan to the Federal Poverty Level is set forth in the Table below. As can be seen, both SMI and FPL vary based on household size. In Michigan, 60% of SMI (for households with one to four persons) ranges from 215% to 231% of FPL.

Table 8. Comparison of 60% of Michigan SMI to 100% of Federal Poverty Level (2024

HH Size	60% SMI[25]	FPL	Ratio
1	$34,849	$15,060	231%
2	$45,752	$20,440	224%
3	$56,295	$25,820	218%
4	$67,019	$31,200	215%

Q. What outreach and intake procedures would you recommend?

A. I recommend that DTE's outreach and intake procedures remain as they are. To the extent that a public assistance program would demonstrate an income-eligibility for the RIA,

[25] https://www.acf.hhs.gov/sites/default/files/documents/ocs/COMM_LIHEAP_IM%202024-02_Att4SMITable_0.pdf.

proof of participation in that assistance program should be accepted as proof of eligibility for the RIA. To the extent that a household does not participate in such a public assistance program, the Company should accept documentation from one of its community-based intake organizations that the customer is income-eligible. It should not be difficult for DTE to identify customers with income up to 200% of the Poverty Level. DTE Electric's seasonal protections extend up to 200% of Poverty Level. DTE Electric has established procedures for identifying households with income up to 200% of Poverty. A household that has been so identified appears in the customer profile of the DTE Electric Customer Relational Management ("CRM") program. A customer who has been qualified for the seasonal protections should be found to have established "special needs" for purposes of the redirected RIA credits.

Customers with incomes at or below 150% FPL and participating in the current RIA would be redirected to the LIA program as I described below.

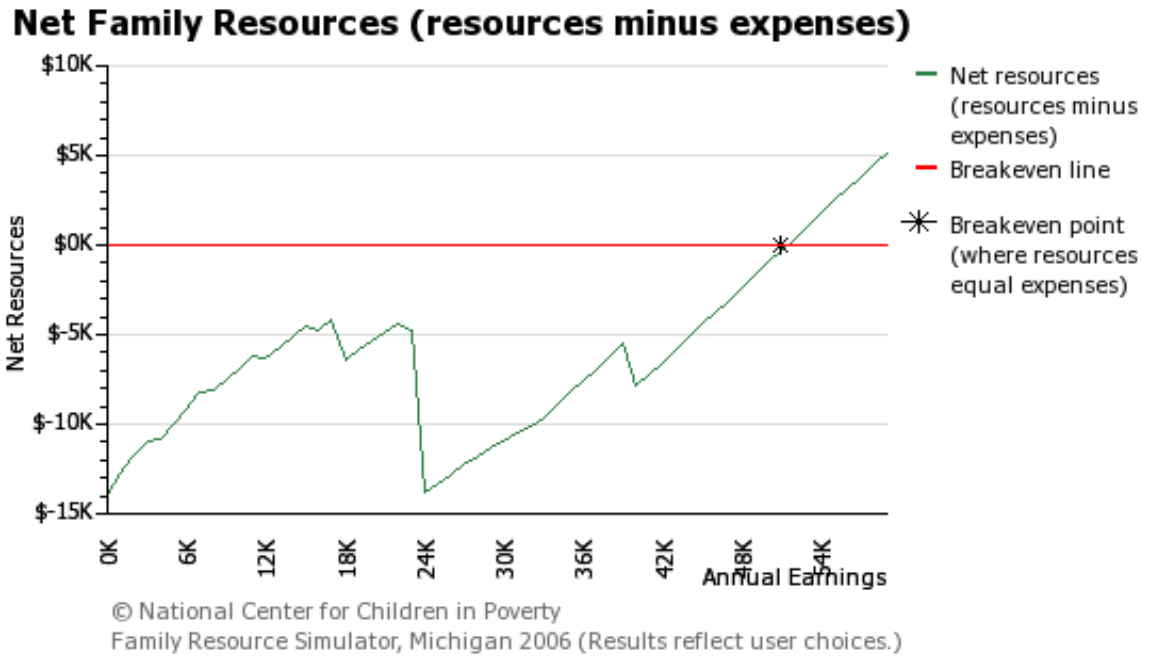
Q. Please explain why you propose that RIA credits be redirected toward these higher income customers.

A. My recommendation has two foundations. First, I have described in detail above how customers who are in these higher income ranges may have somewhat higher incomes (in dollar terms), but they are also customers who have more *fragile* incomes. These customers are those who are commonly referred to as the "working poor." They have incomes that are too high to qualify for benefits but too low to be able to sustainably make payments for their basic household necessities. The Census Bureau's PULSE Survey data which I discuss above (Table 4 and accompanying text) shows that customers falling into these

income ranges that are likely to be the working poor ($35,000 - $75,000) still report having substantial difficulties in paying their "usual household expenses."

Second, simply because income increases does not mean that total household resources available to pay DTE electric bills increases. As incomes increase, a family becomes eligible for fewer and fewer public assistance benefits. For example, for a family of three (one parent, one pre-school child, one school-age child), when income reaches not quite $24,000, total household resources plummet due to the household becoming ineligible for public assistance. I have exercised the "family resource simulator" of the National Center for Children in Poverty for households living in Detroit (MI) to show this impact.[26] Another drop in total resources for this three-person household occurs when the household's annual income exceeds just over $36,000. While this simulation is limited to 2006 data, the impacts of having rising incomes reduce total resources due to a household becoming ineligible for assistance has not changed over time.

[26] The family resource simulator can be accessed at http://www.nccp.org/tools/frs/index.php.



As this simulation demonstrates, a household is not uniformly financially "better off" simply because the household's income increases. Even as family "income" may increase, the net family resources available to pay necessary expenses such as DTE Electric bills does not.

Q. Have you been able to compare the net family resources you identify above with federal poverty level?

A. In the Chart above, the first major reduction in net family resources ($24,000) occurs at roughly 150% of FPL. My proposal for RIA is to redirect toward households who face that precipitous drop in net family resources.

B. The Structure and Operation of the LIA Bill Credits.

Q. Please describe your understanding of the structure and operation of the Low-Income Assistance (LIA) credits.

A. My understanding of the Company's Low-Income Assistance (LIA) Bill Credits is again based on the testimony of DTE witness Sparks in this proceeding. Witness Sparks states that "The LIA credit (contained in Rate Schedule D1.6) offers qualifying low-income electric customers a $40 per month credit on their bill. . .To qualify for this rate an electric customer must have a total household income at or below 150% FPL." He explains that any qualifying low-income customer currently is eligible to receive the LIA credit, "though the Company prioritizes customers who are enrolled in the Company's APP or already receiving the RIA credit."[27] Witness Sparks stated that "Over 38,000 unique households receive the electric LIA credit with an annual monthly average of 32,125."[28]

Witness Sparks finally explained the relationship between DTE's LIA and the Company's Low-Income Self-sufficiency Program (LSP). He stated that "There are several ways a customer may receive the LIA credit. (1) Customers who become enrolled in the LSP program are also enrolled to receive the LIA credit; (2) Graduates of LSP may continue to receive the LIA credit if maintaining their low-income eligibility status; [and] (3) At the Company's discretion, customers receiving the RIA credit can transition to LIA when there is availability."[29]

[27] *Id*., at 17.

[28] *Id*.

[29] *Id*.

Q. Is DTE proposing any change to the LIA Credit in this proceeding?

A. Yes. In this proceeding, DTE is proposing to increase the LIA Bill Credit from $40 per month to $50 per month.[30]

Q. Given the connection between the LIA Bill Credit and the Low-Income Self-Sufficiency Program (LSP), is it important to understand what LSP offers?

A. Yes. According to DTE witness Sparks, the Low-Income Self-Sufficiency Plan (LSP) "is the Company's [Affordable Payment Plan]." The LSP and APP, in other words, are the same program by different names. According to witness Sparks, the LSP "is a 2-year payment plan for vulnerable families at or below 150% Federal Poverty Level (FPL) to make affordable monthly payments based on income and energy usage." Sparks explains that "[t]he plan eliminates any future late payment charges, and past due energy charges are frozen while the customer receives a monthly arrears forgiveness credit."[31]

Q. Have you had an opportunity to consider the impacts of the Low-Income Assistance (LIA) Credit on bill burdens?

A. Yes. Table 8 below shows the impact which DTE's LSP bill credits have on bill burdens experienced by participating low-income customers. These bill burdens examine only the bill for current service. They do not consider the impact on burdens associated with retiring any arrears associated with the account.

As can be seen, while the LIA bill credit has *some* impact on bill affordability, that impact depends largely on the income range into which DTE customers fall with which to begin.

[30] *Id*., at 19.

[31] *Id*., at 4.

For DTE's customers with income at or below 150% of FPL, a significant number of customers at the lowest income ranges will continue to receive unaffordable bills even after receiving an LSP credit. Indeed, even given DTE's proposal to increase the LSP credit from $40/month to $50/month, customers with income less than 100% of FPL will have burdens exceeding an affordable 4% target. Customers with income in the lowest FPL tier (less than 50% of FPL) will have bill-to-income ratios (i.e., bill burdens) that are more than 2½ times higher than the 4% demarcation of affordability.

As would be expected, as incomes increase, bill burdens after receipt of an LSP credit decrease. In the FPL range of 100 to 125% of FPL, the LSP credits result in an affordable burden of 3.7%. Customers with incomes lower in that range would be at or above the 4% affordable level, while customers with incomes higher in that range would have bills that are more affordable.

Table 9. DTE Bill Burdens After LIA Bill Credit Applied (existing and proposed)

	Existing LIA Credit		Proposed LIA Credit	
Poverty Level Range	Bill with Existing LIA Credit ($40)[32]	Burden with Existing LIA Credit ($40)	Bill with Proposed LIA Credit[33]	Burden with Proposed LIA Credit ($50)
0-50 FPL	$1,069	11.7%	$949	10.4%
50-75 FPL	$1,069	7.5%	$949	6.7%
75-100 FPL	$1,069	5.4%	$949	4.8%
100-125 FPL	$1,069	4.2%	$949	3.7%
125-150 FPL	$1,069	3.4%	$949	3.0%

[32] $1,549 – ($40/month x 12 months).

[33] $1,549 – ($50/month x 12 months).

The Table further demonstrates that increasing the LSP credit from $40/month to $50/month would result in little impact on the affordability of bills. For customers at 0 – 50% of FPL, the increase would only result in a reduction in bill burdens from 11.7% to 10.4%, still well above the 4% affordability marker. Customers with income at between 100% and 150% of FPL would experience a reduction in their bill bill-to-income ratios of only between 0.4% (from 3.4% down to 3.0%) and 0.5% (from 4.2% down to 3.7%).

Q. Do you find that the LIA Program is fatally flawed based on your discussion above?

A. No. Unlike the RIA program, whose ineffectiveness represents a fatal flaw in program design, I do not find the LIA program to be so flawed as to merit discontinuation. Instead, the LIA program can and should be modified in ways that would improve its delivery of low-income bill assistance.

Q. On a general level, what modification do you recommend be made to the LIA Program?

A. I recommend that DTE move away from offering a flat across-the-board bill credit through its LIA initiative. As states today move toward adopting low-income assistance, they have largely abandoned the offer of flat across-the-board discounts. As DTE witness Sparks notes, DTE's LIA was first adopted in 2012. Since that time, the "learning" that has arisen has demonstrated the advantage of more closely targeting the bill affordability assistance to different levels of income.

Q. Can you illustrate what you mean by this "learning" from the offer of tiered assistance?

A. Yes. The State of New Hampshire offers what it refers to as a "tiered rate discount" through its Electricity Assistance Program (EAP). I consulted for the New Hampshire commission to help develop the program when it was first adopted. The New Hampshire program provides electricity discounts which vary based on five different tiers of income. The specifics of the tiers, and the specific levels of discount, are not important here. Suffice it to say that each tier was designed so that at average consumption and average incomes in each tier, the discount would result in an affordable electricity burden.

In 2022, I was again asked to review the program to assess what changes, if any, might be merited given that the program had not been reviewed since 2007. In my review of the EAP, I found that New Hampshire's low-income population, without EAP, faces substantial energy burdens. These burdens are four to five times higher than the commonly accepted definition of an affordable percentage of income for total home energy (6%). My evaluation of the New Hampshire EAP documented the importance of the tiering of discounts. I found, in relevant part:

> EAP participants appear to have four distinct regimes of arrearage balances. The first range includes EAP participants with percentage of income burdens of 4% of income or less. These customers tend to have arrearage balances of well below $100 in each month of the study period. The group of EAP participants with percentage of income burdens of between 4% and 8% of income have somewhat higher unpaid balances, with a third grouping encompassing those participants with burdens between 8% of income and 20% of income. When burdens exceed 20% of income, the resulting average unpaid balance substantially increases to reflect the higher burden.
>
> As bill burdens increase the contribution that those higher burden households make to the total level of arrears increases as well. While nearly 40% of all

> EAP accounts have bill burdens of 4% of income or less, the total unpaid account balances appearing on the accounts of those low-burden EAP participants ranges from only 9% to 13%. In contrast, EAP participants with higher burdens have a higher proportion of arrears. In October 2020, for example, 22% of the total unpaid EAP balances appear on EAP bills representing bills burdens of 12% of income or more, even though only 6% of all EAP participants have percentage of income burdens that high. Moreover, 44% of all unpaid balances appear on bills of EAP participants with a bill burden of 8% of income or more, even though only 15% of all EAP participants have percentage of income burdens that high.[34]

As the tiered burdens reduced bills to an affordable percentage of income, in other words, the payment patterns of program participants correspondingly improved as well.

Q. What specific modifications do you recommend for the DTE LIA Initiative?

A. DTE need not adopt a tiered rate discount in order to adopt the principle that its bill affordability assistance should be more closely targeted to customer needs based on household income. DTE should, however, adopt the principle of tiering its LIA benefits based on income. More specifically, I recommend that the LIA program be modified to adopt the following tiered bill credits: (1) income at 0-50% FPL: bill credit of $95/month; (2) income at 50-100% FPL: bill credit of $80/month; and (3) income at 100 – 150% FPL: bill credit of $45/month.

Q. Have you been able to review the impact of this tiered bill credit on DTE bill affordability?

A. Yes. Note that while my proposed LIA tiers reduce the bill burdens for the two lowest income ranges (0 – 50% FPL; 50 – 100% FPL), it results in a somewhat increased burden

[34] Colton (2023). New Hampshire Electric Assistance Program (EAP): Review of Performance / Future Directions, at 38.

for the highest range (100 – 150% FPL). The reason for that, of course, is that while DTE proposes a flat $50 bill credit for all income ranges (an increase from the existing $40 bill credit), I recommend that the bill credit for that third tier (100 – 150% FPL) be increased to only $45/month. Even though I recommend a somewhat lower bill credit for the third tier, the bill burdens that are achieved as a result remain below the 4% demarcation of affordability.

Table 10. Bill Burdens at Proposed LIA Flat Credit and at Tiered LIA Credit

	DTE Proposed LIA Credit		Tiered LIA Credit	
Income Range	Bill at Proposed LIA Flat Credit[35]	Bill Burden at Proposed LIA Flat Credit	Bill at Tiered LIA Credit[36]	Bill Burden at Tiered LIA Credit
0 – 50% FPL	$949	10.4%	$409	4.5%
50 – 75% FPL	$949	6.7%	$589	4.1%
75 – 100% FPL	$949	4.8%	$589	3.0%
100 – 125% FPL	$949	3.7%	$1,009	3.9%
125 – 150% FPL	$949	3.0%	$1,009	3.2%

Q. Do you have any final observations about the RIA credits?

A. Yes. This observation, however, applies to ***both*** the RIA ***and*** the LIA programs. DTE should ensure that application of the RIA and LIA credits are not applied simply to bills for current service. As I discuss elsewhere in this testimony, there are substantial numbers of low-income/senior customers with long-term arrears. The particular impact of that observation is that these customers not only bear the cost of bills for monthly service, but

[35] $1,549 – ($50/month x 12 months).

[36] $1,549 – (tiered credit/month x 12 months). Tiered credits = $95 for 0 – 50% FPL; $80 for 50 – 100% FPL; $45 for $100-150% FPL.

also bear the cost of late payment charges imposed on the arrears. Those additional costs contribute to a household's energy burden no less than the bills for current service do. Accordingly, DTE should ensure that its RIA and LIA credits will be applied to the *total* bill, irrespective of whether the bill is comprised of charges for current service or comprised (in part) of late payment charges.

C. Cost Recovery for the LIA Program.

Q. Have you developed a cost estimate for your modified LIA credits?

A. No. The cost of my modified LIA credits depends on three inputs, only one of which I currently have. First, I need the total size of the population receiving LIA credits. Second, however, I need the distribution of the population receiving LIA credits over income ranges. It is not sufficient, in other words, to project that "x" number of customers are expected to receive LIA credits. It is necessary, also, to know that, within that "x" population, "a" number of customers are receiving a Tier 1 credit ($95/month); "b" number of customers are receiving a Tier 2 credit ($80/month); and "c" number of customers are receiving a Tier 3 credit ($45/month). Third, I need to know the total average number of months of participation in any given year. Not every participant will receive a bill credit in every month in a year. If, for example someone enrolls in June, that customer will contribute only seven months (June – December) of costs to the program budget. Not all program participants will be in the LIA for a full twelve months.

Q. How do you address these unknows in allowing DTE cost recovery?

A. I recommend that DTE be allowed to reconcile its actual LIA costs to its projected LIA costs on an annual basis. Whether those costs are under-recovered or over-recovered, the excess or deficit would be tracked by DTE as a regulatory asset to be included in rates in

DTE's next base rate case. When included in rates, the projected costs, along with the over- or under-recovery, would be recovered in base rates as would any other DTE expense.

Q. Is there a regulatory advantage to including LIA costs in base rates as you recommend?

A. Yes. Including the costs of the LIA in base rates largely renders moot the question of the extent to which we are tracking only the gross costs of the program for inclusion in rates as compared to the true cost of the program. The true cost of the LIA discount program is not solely the gross cost of the program. It also factors in the net incremental costs of the program as well. Therefore, for costs to be recovered, a DTE cost-analysis on the Bill Discount Program should show that (1) only the *incremental* costs of the program should be recovered; and (2) only the *net* costs of the program should be recovered.

Q. Define "gross" program costs.

A. The "gross costs" of the proposed discounts represent the difference between bills to program participants at standard residential rates and the bills to program participants at discounted rates. If, for example, aggregate bills to low-income customers at standard residential rates were $1,000, and aggregate bills to low-income customers at the discounted rates were $650, the "gross cost" of the program would be $350.

Q. Define "incremental" program costs.

A. The "incremental costs" of the proposed discounts are those costs that would not have been incurred had the discounts not existed. If costs would have existed even in the absence of the program, those costs are already being recovered in revenue requirement and thus should not be recovered *again* under the guise of low-income rate discounts.

Q. Define "net" program costs.

A. The "net costs" of the proposed discounts are determined by beginning with the incremental program costs, subtracting cost reductions, and then subtracting revenue enhancements. If adoption of the low-income discount programs generates either enhanced revenues or reduced expenditures, the net costs of the program are reduced.

Q. What are the consequences of considering only the gross program costs?

A. Considering *only* the "gross costs" is based on two fatal assumptions. First, such a consideration assumes that, in the absence of discounts, DTE would collect 100% of the revenue which it bills to low-income customers. Second, DTE would assume that providing more affordable bills to low-income customers would generate no offsetting cost reductions and no offsetting revenue enhancements. Both assumptions are false.

Q. Please describe how a bill for current service is rendered and why that is relevant to an examination of program costs.

A. A bill for *current* service rendered to a participant in the Company's Bill Discount Program is comprised of two parts: 1) at portion of the bill that is charged to participants (the non-discounted portion of the bill); and 2) the portion of the bill that is not charged to program participants and is instead charged to non-participants (the discounted portion of the bill. A cost-recovery analysis that skips over the second part is flawed.

Q. Please explain how a low-income customer's bill is treated *before* a customer becomes an LIA participant.

A. Before a low-income customer becomes a discount participant, the two parts of the bill are not separately recognized. The low-income customer who is not receiving a bill discount

receives a single bill. When that customer cannot afford to pay his or her total bill, the customer frequently pays *less* than the full amount of the bill at standard rates. The cost of filling that gap of revenues that have been billed at standard rates, but not paid, are included in base rates. The gap may be seen in the level of uncollectibles. It is even more often seen in chronically high levels of arrears.

Q. How does the treatment of the bill change after the customer enrolls in the LIA?

A. When a customer enrolls in the LIA, those two parts of the bill are *separately* recognized. After a customer enrolls in LIA, the discount participant is provided a discounted bill (discounted bill), which the participant is expected to pay. The remainder of the bill (discount amount) is charged to other *non*-participants. Accordingly, when a low-income customer enrolls in the LIA, the portion of the bill that the customer previously could not pay, and was paid for in base rates, now becomes the discount amount and is recovered on that basis.

Q. Why is that significant?

This treatment is significant because as LIA participation occurs, DTE collects the amount of the discounted dollars as though the shortfall attributable to the discount is a "new" expense. The participation by low-income customers in the bill discount program, however, does not create "new" costs. Instead, participation in the discount program simply *moves* the unpaid bills out of the group of customers known as "residential" customers and into the group of customers known as "bill discount participants." To allow the dollars of discount credits to be added to rates without correspondingly adjusting for those dollars that already have been included in base rates allows the Company to collect those dollars in *both* places.

Q. Please explain the significance of your reference to "net" costs.

A. If one examines only the dollar amount of the discount, the cost recovery is ignoring the program benefits (i.e., reduced costs, enhanced revenues) that the LIA rate credits would also generate. The most important benefit that is likely ignored is the reduction of arrearage balances and the corresponding impact on reduced working capital. Other benefits include reductions in collections expenses, uncollectable expenses, and enhanced revenues for the program.

Q. Is it unusual for a utility to consider offsetting savings from a utility investment?

A. Of course not. It is a fundamental predicate of utility ratemaking. In energy efficiency planning, for example, one fundamental element is to identify and consider the offsetting "avoided costs" from the efficiency investments. One does not consider simply the gross costs of the investment. In addition, when I litigated rate cases as an attorney, one issue I litigated was whether self-insurance was justified by the offsetting cost reductions from avoided insurance premium payments. One issue we litigated also was whether maintaining compensating bank balances generated offsetting cost reductions in avoided bank fees. To ignore the savins from a utility expenditure by allowing the cost without netting out the avoided costs as savings would be an unmerited exception to fundamental principles of utility ratemaking.

Q. Please explain why DTE would be expected to have a reduction in working capital that it should consider in a determination of LIA cost recovery.

A. Working capital expense is driven by two factors: (1) the *level* of arrears; and (2) the *age* of arrears. For example: (1) an arrearage of $1,500 generates a greater working capital expense than an arrearage of $500 (all else equal). (2) An arrearage that is 120 days old

generates a greater working capital expense than an arrearage that is 60 days old (all else equal). So, if an appropriately designed, targeted, and funded low-income discount program can reduce the number of low-income customers in arrears, the dollars of arrears which low-income customers carry, or the length of time that arrearages remain outstanding, there is a working capital reduction that redounds to the benefit of all ratepayers.

Q. How and why are the "net" costs relevant to a discussion of LIA cost recovery?

A. DTE's LIA program will generate working capital savings for the Company by reducing both the level of arrears and the age of arrears. My proposal will generate savings by reducing the level of arrears; it will also generate savings by reducing the age of arrears. In addition, it will generate additional offsets by enhancing revenue and reducing costs such as credit and collection expenditures and uncollectible expenses. In calculating the impacts of the LIA on nonparticipating ratepayers, it is necessary to consider not only the ways in which LIA will increase costs, but also the ways in which the LIA will decrease costs.

Q. Please summarize why this discussion supports inclusion of LIA costs in base rates rather than through a rider?

A. Even if cost recovery is reconciled as I recommend above, recovering LIA costs only through base rates allows the Company (and the Commission) to avoid the need to specifically dollarize and quantify the cost savings to offset LIA program costs. The recognition of reduced expenses would occur in the overall determination of what DTE's revenue requirement would be. Unless one wants to know for some theoretical reason what the revenue requirement *would have been* in the absence of the LIA, the savings and other

benefits generated by the LIA are captured in the rate-setting process. All that would need to be done is to assure that historic uncollectibles and working capital are adjusted to ensure that bills historically not paid by program participants are not double-collected.

D. Expanding Participation of the LIA Population.

Q. What are the implications to program enrollment arising from your discussion of the cost advantages derived from the LIA?

A. The discussion above demonstrates that DTE derives real advantages to itself and its nonparticipating ratepayers from expanding the enrollment of LIA participants. Even should DTE find that it does not generate sufficient financial benefits to completely offset the costs of providing LIA credits, it is not possible to reach any conclusion other than that the net incremental cost of LIA will be substantially less than the gross costs of providing the credits. For that reason, imposing a ceiling on program participation as a cost control measure no longer is justified. Accordingly, I recommend that the Commission remove the cap on both the RIA and the LIA ceiling enrollment and allow the programs to achieve whatever participation is possible.

Q. Is there a second program enrollment impact that should result from the cost advantages derived from the LIA?

A. Yes. I recommend that DTE expand its LIA program to provide for the enrollment of self-attested recipients of assistance through the federal Supplemental Nutrition Assistance Program (SNAP) (formerly known as Food Stamps). Additional programs, a determination of eligibility for which would also establish a household's low-income status, should be included, also, over time as the Commission determines which programs would serve the purpose of facilitating enrollment by eliminating administrative barriers to enrollment. For

example, such programs might include, but not be limited to, Medicaid, LIHEAP, Free School Lunches, and the like.

Adding additional programs is not unusual. Work I did in Rhode Island on behalf of the Department of Public Utilities resulted in Narragansett Electric Company providing a 25% discount on total bills for income-qualified customers. However, if customers participate in particular programs generally associated with *very* low incomes (Medicaid, Rhode Island Works Program, Public Assistance), the utility provides a 30% discount. In this fashion, the utility offers greater assistance to customers with the lowest income.

In addition, Massachusetts has an expanded approach to determining eligibility for its low-income discount. In Massachusetts, enrollment in the discount program(s) is automatic once a customer provides evidence of enrollment (such as a program ID or a program acceptance letter) in one of a dozen income-qualified programs: LIHEAP; Emergency Aid to Elders, Disabled, and Children (EAEDC); Food Stamps (SNAP); Head Start; MassHealth (Medicaid); National School Lunch Program; Public Housing; School Breakfast Program; Supplemental Security Income (SSI); Transitional Aid to Families with Dependent Children (TAFDC); various Veterans' benefits programs; or Women, Infants and Children (WIC). Care must be taken, however, in thinking of Massachusetts as directly applicable. While the Massachusetts enrollment is expansive, care must be taken to consider the trade-offs for this "automatic enrollment" process. Massachusetts can rely on this type of eligibility determination only because the program requires utilities to know only *whether* a customer is low-income. Given that every customer receives the *same* level of discount, knowing the actual income of the customer (or the actual Poverty Level) is not necessary, since it is not used in any determination.

Vermont's largest gas utility has adopted an approach akin to that used in Massachusetts. The utility offers an across-the-board 20% discount to customers with income at or below 185% of Federal Poverty Level. Customers enroll through an application form processed through the State Department for Children and Families. On that application form, a customer checks-off whether they participate in a range of programs that would also income-qualify them for the natural gas discount. Once the Department confirms that participation, it notifies the utility, which then enrolls the customer in the discount program. While program enrollment is thus widely available, program benefits are a yes/no toggle. A customer is either eligible or is not eligible. No differentiation in benefits is provided based on income.

I conclude that while the type of expedited enrollment I discuss further below is not uncommon, there are multiple ways in which it can be implemented. DTE should work with stakeholders to develop the approach that would be most appropriate for Michigan.

Q. How many SNAP recipients live in the DTE Electric service territory?

A. The SNAP program does not report participation data disaggregated by utility service territory. Nonetheless, it is possible to obtain a reasonable estimate of the number of DTE customers who are SNAP recipients. Using the same list of DTE zip code I explained above, I determined that 12.53% of the total number of households in zip codes served by DTE receive SNAP benefits.[37] DTE's EIA Form 861M data for the first four months of 2024 –the most recent 861M data available—then reports that DTE served an average of 2,064,746 customers a month in 2024. Combining those two numbers yields an estimated

[37] American Community Survey (5-year data) (2022), Table B22002.

SNAP population in DTE's service territory of 258,713 (rounded to 260,000) households). Achieving an additional new participation of even 25% of these SNAP households would generate an additional LIA participation of 65,000 households.

Q. Please explain why you recommend automatic enrollment for food stamp participants.

A. I explain in detail earlier in my testimony the relationship between low-income status and payment difficulties. In particular, I explain the relationship between home electric *burdens* and the unaffordability of home electric service. SNAP participants in DTE's electric service territories have average incomes[38] that would indicate that their home electric burdens would be high. In the 445 DTE zip codes reporting median incomes for SNAP recipients, only 98 would have a DTE electric burden of less than 4% of income at the rates proposed in this proceeding. In contrast, 30 would have a DTE electric burden of 10% or more, 74 would have a DTE electric burden of 8% or more, and 133 would have a DTE electric burden of 6% of income or more.

Q. Please explain what you mean by self-attested enrollment.

A. DTE's tariff for its D1.6 Pilot Program already provides as follows:

> To qualify for this pilot rate a customer must also provide annual evidence of receiving a Home Heating Credit (HHC) energy draft or warrant, *or* must provide confirmation by an authorized State or Federal agency verifying that the customer's total household income does not exceed 150% of the poverty level as published by the United States department of health and human services *or* if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid. Service under this rate shall be limited to an annual average of 32,000 customers.

[38] American Community Survey (5-year data) (2022), Table B22008.

(emphasis added). What I propose, therefore, is not an expansion of the eligibility to receive LIA credits. DTE'[s use of the term "or" means that the three listed criteria are alternative means of establishing eligibility. A customer may, but need not, have their household income verified by a state or federal agency. Rather an expanding the eligibility criteria, I simply recommend an expansion of the specific manner in which a DTE customer may document that they meet the eligibility criteria that *already exist* in the program. What I recommend is that a customer should be enrolled to receive LIA credits if they can provide documentation of their participation in the SNAP (Food Stamp) program. No further income certification, and no further application process, would be required.

Q. Please explain why you recommend that this self-attested enrollment of SNAP recipients be adopted.

A. One advantage of extending the LIA credit to self-attested SNAP recipients is to maximize the synergies between the receipt of SNAP and improvements in DTE bill payment patterns by low-income customers. Research at the University of Michigan's National Poverty Center documents that the receipt of benefits through the Supplemental Nutrition Assistance Program (SNAP, formerly known as Food Stamps) helps low-income customers improve their utility bill payments.[39] The research of Shaeffer and Gutierrez was designed to examine the impact, if any, of SNAP assistance on the reduction of "material hardships," beyond food hardships, on households with and without children.

[39] H. Luke Shaefer and Italo A. Gutierrez, "The Supplemental Nutrition Assistance Program and Material Hardships among Low-Income Households with Children," Social Service Review 87, no. 4 (December 2013): 753-779.

Nonpayment of utility bills was one of the "material hardships" considered. The study reported that "we find a statistically significant and substantively large negative relationship between SNAP participation and both food insecurity and the ability of families to pay essential household expenses, particularly, housing expenses." According to the researchers, "SNAP participation may reduce other aspects of material hardship as well by allowing recipients to reallocate resources originally directed toward the purchase of food to other essential expenses such as housing and utility costs."

Their findings stated that "SNAP has a sizeable effect not just on the food security of households with children, but also on their non-food material well-being also." In particular, the study found a "statically significant negative relationship between SNAP participation and the risk that households will fall behind on their. . .utilities." The receipt of SNAP reduced the percentage of households with children not paying their utility bills by 46.8% (from 33.5% to 17.8%).

Given the benefits that the receipt of SNAP benefits generates to DTE, it is reasonable to allow those SNAP recipients to avail themselves of the LIA credit.

E. Relationship to DTE's Pilot Percentage of Income Program.

Q. Please explain the relationship between your recommendations above and DTE's pilot Percentage of Income Program.

A. There is no relationship between my recommendations above and the Company's ongoing efforts to deliver and evaluate a Percentage of Income Program (PIP). I understand that the Pilot process is a continuing process. That process should be allowed to finish. My recommendations above, therefore, are independent of the existing Pilot PIP.

V. PART 3. PROPOSED MODIFICATIONS TO DTE'S ARREARAGE FORGIVINESS PROGRAM (AFP)

Q. Please explain the purpose of this section of your testimony.

A. In this section of my testimony, I recommend modest modifications to improve the operation of DTE's Arrearage Forgiveness Program. I recommend modifying DTE's existing arrearage forgiveness program in the following four ways: (1) to allow program participants to earn forgiveness of a pro rata portion of participants' pre-program arrears for each month they make a complete payment; (2) to allow for forgiveness for each "complete" payment made whether or not that payment was made in a "timely" fashion; (3) to allow for complete forgiveness of a program participant's entire arrears over a two-year period; and (4) to allow a tiering of arrearage forgiveness to provide greater benefits to the lowest income customers.

Q. What is your understanding of DTE's arrearage forgiveness program?

A. As with my discussion of the RIA and LIA programs above, my understanding of the three aspects of DTE's arrearage forgiveness program which I recommend being modified is based on my reading of the Direct Testimony of DTE witness Jason Sparks. Witness Sparks explained the arrearage forgiveness program. Sparks testified that arrears are forgiven over a 24 month period, with an upfront forgiveness of up to $600, a second $600 forgiveness at 12 months, and a final payment of $1,800 at the "completion" of the plan.[40] Sparks does not define what it means to "complete" a plan. He does introduce, however, two different concepts. First, there is the concept of being "successful" on the plan. He states that "in the current LSP program, a household is considered successful when completing the fiscal

[40] Direct Testimony of Jason Sparks, at 9.

year without being removed for non-payment."[41] He further explained that the measure of "success" on an annual basis is "customers avoiding disconnect due to missed payments."[42] It should be clear, however, that simply because a customer had not been disconnected for nonpayment does not mean the customer was not having payment difficulties. In DTE's Monthly COVID-19 Response Data Report (Docket U-20757) for the month of May 2024, for example, DTE reported that it had issued 11,602 discontinuation notices to "senior/low-income" electric customers in May 2024, but actually physically disconnected service to only 259 of those customers. While not distinguishing between gas and electric customers and/or arrears, DTE further reported in that May 2024 filing that it had 104,022 "senior/low-income" customers 90 days or more in arrears,[43] and an *additional* 9,382 "senior/low-income" customers 61 – 90 days in arrears.[44] The number of senior/low-income customers[45] in arrears were substantially in arrears. The average dollar arrears of senior/low-income customers 90 days or more in arrears was $760.

Second, witness Sparks introduces the notion of "graduating" from the LSP. He states, however, that "in the current program format, in addition to customers achieving a zero balance for graduation status, customers are provided 24 months of eligibility on the program and graduation can occur for those customers who complete the 24 months even

[41] *Id*., at 9.

[42] *Id*., at 10.

[43] This is defined as including accounts where the oldest arrears is in the 90+ day bucket as of month end.

[44] Likewise, this is defined as including accounts where the oldest arrears is in the 61 – 90 day bucket as of month end.

[45] "Low-income" is defined as 200% of Federal Poverty Level or less. "Senior" is defined as age 65 or older.

with a balance."[46] As is seen, in other words, being "successful" on the LSP and "graduating" from the LSP are two *different* concepts. It is not clear whether to "complete" an LSP plan means to be "successful" (as defined by Sparks), to "graduate" from LSP (as defined by Sparks), or something entirely different.

Q. What percentage of LSP customers "graduate" from the LSP?

A. According to witness Sparks, for the three most recent program years (2020-2021, 2021-2022, 2022-2023), DTE had an average of 24,453 participants in LSP, of whom a total of 15,299 were "eligible" for graduation. Of those "eligible" for graduation, a total of 10,561 actually "graduated."[47] Mr. Sparks said that being "eligible" for "graduation" means either that the program participant achieved a zero balance *or* that the program participant had been on the LSP for 24 months. He did not report how many, or what percentage, of LSP participants completed the LSP "with a balance."

Q. Would you expect the "graduation" rates in the 2020-2021 and 2021-2022 program years to be artificially high?

A. Yes. Particularly in the 2021-2022 program years (the year in which LSP graduation climbed to 74% of those eligible), the federal government distributed an historically high amount of LIHEAP assistance. Comparisons to this program year are thus not helpful to any determination of what might reasonably be expected on an ongoing basis. Consider, for example, what one White House announcement stated:

[46] Direct Testimony of Jason Sparks, at 11.

[47] *Id*.

> Michigan has received a record $384.7 million for the Low Income Home Energy Assistance Program (LIHEAP) available this fiscal year (October 2021 to September 2022). As part of a state-by-state breakdown of funding, the Administration reported that in addition to an annual appropriation of $146.5 million for Michigan, the state received an additional $238.2 million in funds from the American Rescue Plan – *more than double the state's typical annual funding. The total of $384.7 million is the highest amount Michigan has ever received in LIHEAP* to help families struggling with the costs of home heating. (emphasis added)[48]

The White House announcement stated: "In 2021, the Biden-Harris Administration and Congressional Democrats delivered $8 billion in LIHEAP funding nationally, **more than doubling typical annual appropriations** due to $4.5 billion provided by the American Rescue Plan. This is the largest appropriation in a single year since the program was established in 1981. These resources are already allowing states across the country to provide more home energy relief than ever before."[49] It would be unreasonable to expect LIA graduation rates to continue at the same level as federal LIHEAP appropriations return to their historic norms.

Q. What do you recommend?

A. I recommend two modifications to the manner in which DTE grants its arrearage forgiveness credits. First, I recommend that rather than providing arrearage forgiveness credits only at three program points (the beginning of participation, the 12-month mark, the 24-month mark), program participants receive a pro rata forgiveness of their pre-program arrears for each complete bill payment they make over their 24-months of participation. In this fashion, the arrearage forgiveness program responds to complete bill

[48] Available at https://www.whitehouse.gov/wp-content/uploads/2022/01/LIHEAP-michigan.pdf.

[49] *Id.*, emphasis in original.

payments by allowing program participants to see a continuing reduction in their pre-program arrearage balance. Second, I recommend that arrearage credits be provided for each complete payment, and that retroactive credits be provided when a previously missed payment is "cured" such that the bill balance is brought to $0.

Q. Why do you not recommend that credits be provided when payments are both full and "timely"?

I specifically decline to recommend that arrearage credits be granted only upon a full and timely basis. Imposing a "timeliness" requirement does not recognize the economic realities facing low-income households. One attribute of the income of households considered to be "low-income" is not merely the *level* of income, but also is what is known as the *fragility* of income as well. Low-income workers can have their ability to pay utility bills threatened due to unavoidable disruptions in their economic lives as discussed above. A personal illness requiring time off or the illness of a child requiring time off generally represents a permanent loss of income. The jobs of low-wage workers simply do not provide the paid leave required to respond to such circumstances. The lack of flexible work arrangements to lower wage workers also presents situations leading to a potential inability to pay utility bills at a particular time.

Q. Is there a potential "middle ground" between providing arrears credits for full payments and providing arrearage credits for full and timely payments?

A. Yes. While I do not recommend it since it does not allow a customer to see a continuing decline in their pre-program arrearage balance, a potential middle ground is to provide arrearage credits only for full and timely payments on a month-to-month basis. However, in addition, if a customer completes the 24 month forgiveness period with a $0 balance,

whatever pre-program arrears remained on the participant's account that had not been forgiven (due to the lack of a timely payment) would be forgiven at that time. This approach rewards timely payments each month, but also recognizes the fact that a program participant's entire bill had been paid over the 24-month period.

Q. Is there a final modification you recommend for DTE's arrearage forgiveness program?

A. Yes. As I demonstrate in my testimony above, my recommended tiering of LIA benefits substantially reduces the DTE electric burdens to participating customers. For customers with income at 0 – 50% of FPL, however, while my recommended LIA credit would reduce their DTE electric burden from 10.4% to 4.5% (Table 9), the DTE electric burden for this lowest income customer base remains somewhat above the 4% demarcation of affordability. Even under my recommendation, in other words, customers with the least ability to pay will be required to pay the highest DTE electric burdens. Accordingly, even after providing the EIA credit, the customers in this lowest income range will have the most difficulty paying their bills in a complete fashion over a full 24-month period.

This impact can be offset by recognizing the increased payment difficulty which even a modified LIA credit imposes on the lowest income participants. This recognition can, and should, be accomplished by allowing customers with income in this lowest income bracket (0 – 50% FPL) to earn their complete arrearage forgiveness over a 12-month period rather than a 24-month period. This tiering of forgiveness credits sends the message that the program recognizes the higher payment problems which remain, even after adopting a tiered LIA credit, but will thus reward full payment over a shorter period of time.

Q. Does this complete your direct testimony?

A. Yes, it does.

MS. ANDREWS: Thank you. Next, on behalf of the Attorney General Dana Nessel, the Michigan Environmental Council, and the Natural Resources Defense Council, I move for the admission of the Direct Testimony -- or I move to bind into the record the Direct Testimony of Mr. Paul Alvarez, which consists of a cover page, table of contents, 66 pages of questions and answers, and for the admission of Exhibits MEC-1 through MEC-9.

JUDGE WALLACE: O.K. Is there any objection to binding in the direct testimony of Mr. Alvarez?

Hearing none, the testimony is bound in.

Is there any objection to the admission of Exhibits MEC-1 through MEC-9?

Hearing none, those exhibits are admitted.

(Testimony bound in.)

- - -

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.	U-21534

DIRECT TESTIMONY OF PAUL J. ALVAREZ

ON BEHALF OF

ATTORNEY GENERAL DANA NESSEL,
MICHIGAN ENVIRONMENTAL COUNCIL, AND
NATURAL RESOURCES DEFENSE COUNCIL

July 26, 2024

DIRECT TESTIMONY OF PAUL ALVAREZ FOR AG-MNS
CASE NO. U-21534

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DIRECT TESTIMONY OF PAUL ALVAREZ FOR AG-MNS
CASE NO. U-21534

I. INTRODUCTION, QUALIFICATIONS, AND PREVIEW

Q. Please state for the record your name, position, and business address.

A. My name is Paul J. Alvarez. I lead the Wired Group, a small consultancy dedicated to the needs of consumer, environmental, and business advocates in state utility regulatory proceedings. My business address is P.O. Box 620756, Littleton, CO 80162.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of a group of parties, including the Attorney General (AG), Michigan Environmental Council (MEC), and Natural Resources Defense Council (NRDC), collectively referred to as "AG-MN".

Q. Please summarize your experience in the field of utility regulation.

A. I have been actively involved in the electric utility industry for 23 years. After a series of finance, marketing, and product management roles in large corporations operating in competitive markets, my utility industry experience began in 2001 as a product development manager with Xcel Energy. At Xcel Energy I oversaw the development of new demand-side management ("DSM") programs and became familiar with the various types of cost-effectiveness tests that are applied to such programs as standard practice. In 2010 and 2011, I led teams that completed the first two independent evaluations of smart grid investment program benefits as the utility practice leader for a boutique sustainability consulting firm.[1] I started the Wired Group in 2012 to focus exclusively on distribution

[1] Colorado PUC 11A-100E, *Smart Grid City Demonstration Project Evaluation Summary*, Xcel Energy report filed as Exhibit MGL-1, Direct Testimony of Michael G. Lamb (December 14. 2011); Ohio PUC 10-2326-GE-RDR, *Duke Energy Ohio Smart Grid Audit and Assessment*, Staff report filed June 30, 2011.

utility planning, investment, performance measurement, and regulation. I wrote "Smart Grid Hype and Reality: A Systems Approach to Maximizing Customer Return on Utility Investment" in 2014 and updated it with a 2nd edition in 2018. I occasionally teach a graduate course at the University of Colorado's Global Energy Management Program, and occasionally teach regulators and Staff at Michigan State University's Institute of Public Utilities. I also publish papers and present at conferences on distribution utility planning, investment, performance measurement, and regulation. I received an undergraduate degree in finance and marketing from Indiana University's Kelley School of Business in 1983, and a master's degree in management from the Kellogg School of Management at Northwestern University in 1991. My curricula vitae is attached as Ex MEC-1.

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

A. Yes. I submitted testimony on behalf of AG-MNS and Citizens Utility Board of Michigan in the most recent rate application from DTE Electric Company ("DTE" or "Company").[2] I am also known to the Michigan Public Service Commission ("Commission") and Staff via work with my Wired Group associate Dennis Stephens on behalf of the Association of Businesses Advocating for Tariff Equity ("ABATE"), for whom we developed several sets of Commentary in recent years. In U-20147, we helped ABATE develop Comments regarding (1) The development of five-year distribution plans in Michigan generally (September 11 and November 18, 2019); (2) Five-year distribution plans and storm performance (October 1, 2021); (3) Consumers Energy's Distribution Infrastructure Investment Plan (June 23, 2021); and (4) DTE Electric Company's Distribution Grid Plan

[2] Case No. U-21297, Direct Testimony of Paul J. Alvarez, 6 TR 3311 *et seq*.

(September 29, 2021). We also helped ABATE develop Comments in U-21122, the August 2021 storm reliability performance and distribution planning docket, (September 24, 2021). Mr. Stephens and I also gave a presentation on distribution planning and utility proposal cost-effectiveness testing, to include risk-informed benefit-cost analysis and risk-informed investment decision support, in a Staff-led workshop on distribution plan development held August 14, 2019.

In addition, I have testified on behalf of consumer, business, and environmental advocates in proceedings related to electric distribution utility planning, investment, performance, and regulation before 16 other state utility regulators in the past 11 years, including California, Georgia, Illinois, Indiana, Kansas, Kentucky, Maryland, Massachusetts, New Hampshire, New Jersey, North Carolina, North Dakota, Ohio, Oklahoma, Virginia, and Washington. A complete list of proceedings in which I've submitted testimony to state utility regulators, with proceeding numbers and dates, can be found in Exhibit MEC-1.

Q. What is the purpose of your testimony?

A. I am testifying on behalf of AG-MNS regarding the financial, policy, and regulatory issues presented by DTE's application as they relate to DTE's electric distribution system. My testimony was developed in close cooperation with my Wired Group colleague, AG-MNS witness Dennis Stephens, who covers the technical aspects of the Company's distribution grid capital spending. Mr. Stephens and I recommend our testimonies be reviewed and considered together, as the financial, policy, and regulatory issues I cover in this testimony

are related to what we consider to be unnecessary, premature, or cost ineffective capital spending, which Witness Stephens covers in his testimony.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

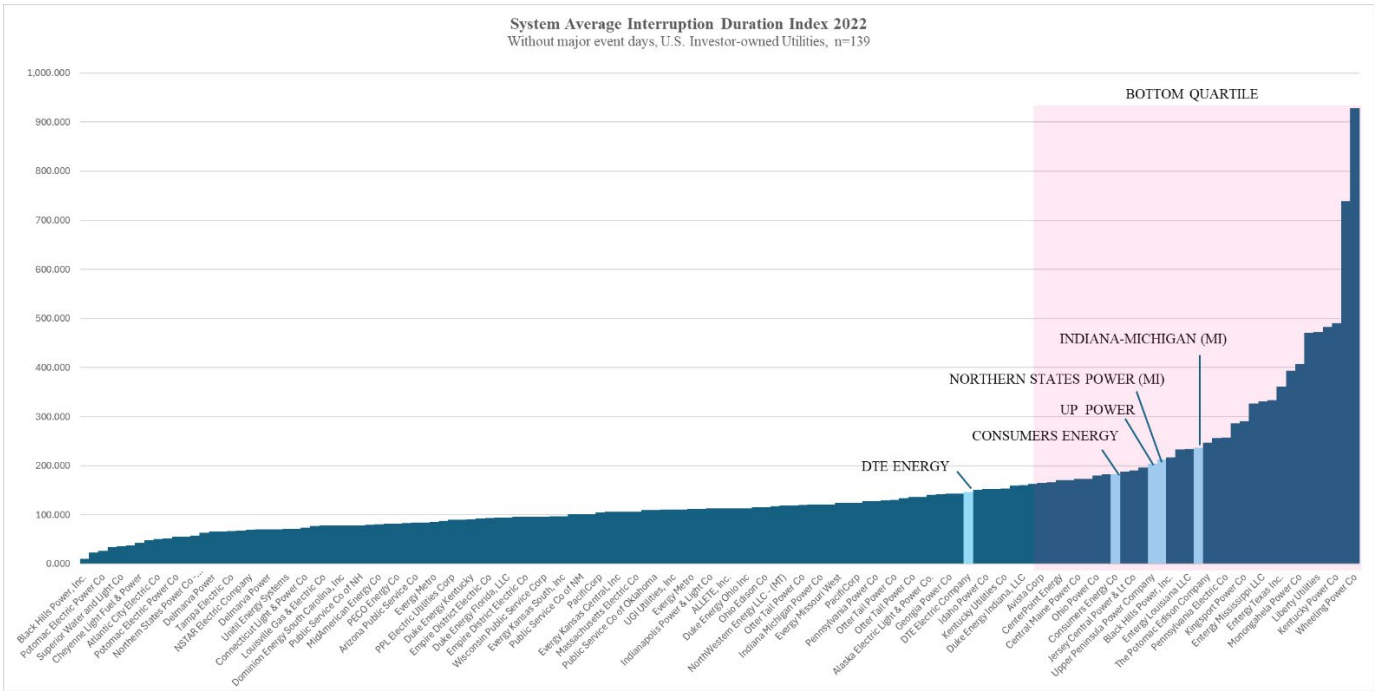
Exhibit MEC-1:	Curricula Vitae of Paul J. Alvarez
Exhibit MEC-2:	Company Response to MNSCDE-2.5 + Attachments *22 Monthly Rate Benchmarking, April 2024* and *25 Spring 2023 Annual*
Exhibit MEC-3:	Company Responses to MNSCDE-15.25(c) – (h) + Attachment *U-21534 MNSC 15.25g-h PTMM Journal Entry Logic*
Exhibit MEC-4:	U-20162, DTE Electric, March 1, 2024, Tree Trim Annual Report
Exhibit MEC-5:	Company Supplemental Response to MNSCDE-8.5(c) (SI) with Attachments *2022, 2023, and 2024 Budget Appropriations*
Exhibit MEC-6:	Company response to MNSCDE-8.16(d)(i)
Exhibit MEC-7:	Company response to MNSCDE-7.2(h)
Exhibit MEC-8:	Company response to MNSCDE-7.4(a) – (d)
Exhibit MEC-9:	Company response to MNSCDE-7.3(a) – (f)

Q. Please provide a preview of your testimony.

A. DTE's capital spending has skyrocketed in recent years, and the Company's pending rate increase application and 2023 Grid Distribution Plan (Exhibit A-23 Schedule M8) forecast even greater capital spending in the future. While Witness Stephens and I appreciate the

Commission's well-placed concerns about grid safety, reliability and electrification "readiness" (for electric vehicles and heating), we are also concerned about the adverse impact of rapidly increasing electricity costs on Michigan's economy generally, and on the Company's low-income consumers specifically. We are also concerned that rapidly increasing electric rates will harm consumer and commercial adoption of the very same electric end-use technologies for which significant electric grid investment is being contemplated. A simultaneous focus on both reliability and readiness can lead to extreme rate increases, absent careful capital spending governance and difficult choices. Unfortunately, it appears to Mr. Stephens and I that such careful governance has not kept pace in Michigan, and worse, that insufficient controls are in place to optimize capital spending decisions, or even to monitor the cost-effectiveness of the capital being spent.

A consistent theme throughout this testimony is that more rigorous regulatory controls over the Company's capital spending are necessary. While we observe that many state utility regulators are being challenged by the need to balance grid investment with affordability, DTE's poor historical reliability record puts additional pressure on this Commission. Indeed, DTE barely exceeds bottom-quartile average interruption duration performance among U.S. investor-owned utilities, and Consumers' Energy, Indiana-Michigan Power, and Northern States Power are all bottom-quartile performers on this metric.



In light of these observations, we encourage the Commission to adopt a more forceful and involved role in regulating the distribution performance and spending of Michigan utilities, beginning with this DTE application. While the Commission's distribution planning dockets are notable, and a step in the right direction, these efforts appear to have been largely ineffective at improving reliability performance or governing capital spending so far.

This testimony is designed to illuminate multiple regulatory opportunities for improving performance and governing capital spending at DTE by balancing reliability and readiness objectives with affordability. It begins by providing more historical context and perspective, with particular attention paid to DTE spending and performance. It continues with one testimony section each on the policy issues presented by DTE proposals for the Infrastructure Recovery Mechanism ("IRM") and vegetation management cost

recovery. The testimony continues with a section on the Company's Global (project and program) Prioritization Model and distribution Reliability Model (used to project reliability improvements from several strategic capital programs). The final section of this testimony addresses DTE's fiber optic data communications cable deployment proposal. This testimony intends to provide perspective, information, and ideas the Commission will find helpful as it considers the Company's application.

Q. Please summarize your recommendations in this testimony.

A. The primary recommendations I make in this testimony include that the Commission:

- Require DTE to slow the rate of capital spending and assess the benefits of its vegetation management program relative to strategic capital spending aimed at improving reliability.
- Reject the Company's request to extend and expand the IRM;
- Regarding DTE's capitalization of vegetation management costs (other than Surge securitization), require DTE to itemize the costs, assess their impact to ratepayers, and support its practice in the next rate case;
- Reject the Company's request to earn a return on the Enhanced Tree Trim Program (ETTP) Surge regulatory asset;
- Reject the Company's request to increase ETTP spending in 2026;
- As the Company approaches the end of the ETTP Surge, require DTE to continue annual tree trim reporting and order an independent audit of the state of DTE's overhead line rights of way every five years, commencing in 2025 or 2026;
- Recognize DTE's Global Prioritization and Reliability Models are unreliable;

- Reject the Company's fiber-optic data communications cable deployment plan and disallow all proposed bridge and test year spending for Grid Automation Telecommunications; and
- Require DTE in its next rate case, if it proposed further spending on the Grid Automation Telecommunications program, to present a make versus buy analysis of alternatives and a tool to identify appropriate alternatives.

II. CONTEXT AND PERSPECTIVE

Q. Please preview this section of testimony.

A. This section of testimony provides context and perspective for Commission consideration as it evaluates DTE's application, doing so in several steps. It begins with a summary of DTE's application, putting the Company's requests and proposals in this rate case into perspective with recent rate cases. It also summarizes relevant portions of the Company's updated 2023 Distribution Grid Plan, and of Michigan's Healthy Climate Plan and Clean Energy Future legislation, with observations and commentary provided.

Q. Please summarize DTE's instant application.

A. DTE's application describes a strategic imperative "to rebuild, modernize, and automate our 46,000 miles of electric circuits (the 'grid') to achieve reliability that is better than industry average by 2029."[3] The Company predicts that $9 billion in grid investment 2024-2028 will reduce outage frequency 30% and outage duration 50%, delivering $15 billion in benefits to DTE customers.[4] (The Company's application also refers to $7 billion in

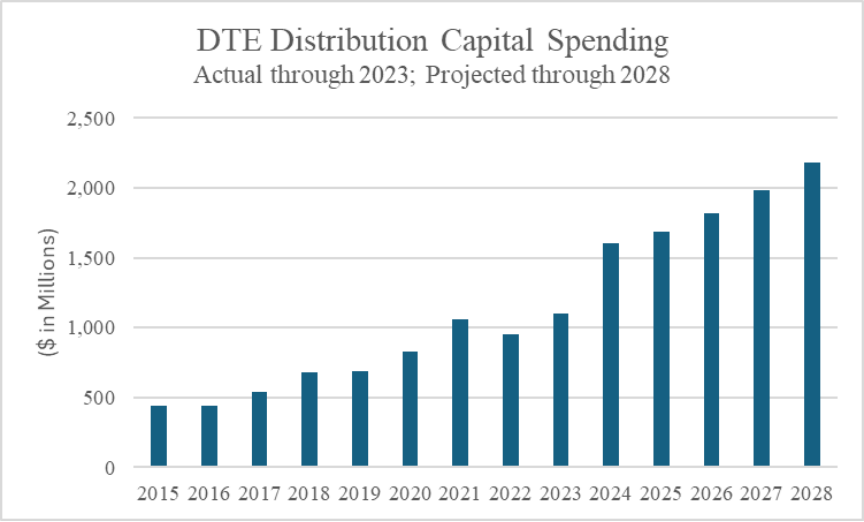
[3] Revised Direct Testimony of Neal T. Foley at NTF-4.

[4] Ibid at NTF-5 to NTF-9.

clean generation investment over the same time period, though generation is outside the scope of this testimony.) The distribution investments are consistent with those the Company explains in its 2023 Distribution Grid Plan (Exhibit A-23 Schedule M8). In addition to massive increases in capital spending, the Company requests that its IRM rider be extended and expanded.

Q. Do these proposals concern you?

A. Yes. Generally, the proposals accrue to shareholders' benefit and increase risks for customers. I will address the IRM later in this testimony, but I am particularly concerned by massive increases in distribution capital spending for improving reliability. Projected distribution capital spending relative to historic capital spending is presented in the chart below.[5] By 2028, DTE's Distribution Grid Plan projects annual distribution spending more than triple the amount it spent in 2018. Capital spending is not necessarily the most reasonable way to improve reliability.



[5] DTE FERC Form 1, line 75, 2015-2023; DTE 2023 Distribution Grid Plan, Ex. 6.6.1, Ex A-23 Sch M8, p. 56 of 264, 2024-2028.

Q. What is the relationship between capital spending increases and rate increases?

A. Rates will not increase as fast as capital spending, because capital cost recovery is spread out over the depreciation period of the underlying assets. But while capital cost recovery is spread out over time, associated rate increases will be no less real nor any less significant, and they will persist for decades (as the typical depreciation period for a distribution asset is generally 40 years).[6] As every resident and business uses electricity, electric rate increases act as a drag on Michigan's entire economy. As indicated above, the Commission must determine the appropriate balance between capital spending and affordability.

In doing so, the Commission should be evaluating if DTE is presenting compelling responses to these difficult questions:

- What are the most appropriate targets for reliability, and over what time frames?
- What are the most cost-effective ways to reach the reliability targets?
- What are the most prudent ways to measure grid "readiness" for electrification?
- At what speed will electrification proceed (dictating the pace of readiness)?
- How can DTE's Distribution Grid Plan be optimized to provide the biggest reliability and readiness benefit per dollar of customer rate increases?

Shareholders are best served by massive rate base growth (which increases the opportunity to earn income) as fast as the Company can possibly manage it (thereby

[6] DTE applies a depreciation rate of 4.11% to distribution capital that is projected to be in-service. Company response to MNSCDE-15.30.

increasing share prices, which are based largely on earnings, prospects for growth in earnings, and perceived shareholder risk). In contrast, rate increases are mitigated by moderating and deferring capital spending, and by prioritizing operations and maintenance ("O&M") solutions over capital solutions where appropriate. Regulators often underestimate the difference in costs to customers between capital and O&M spending. Customers pay returns on capital and taxes on top of the Company's capital costs. In the instant case, for the projected test year, the Company requests a 4.24% interest expense on debt, a 10.50% return on equity capital,[7] and an additional 35% premium on projected DTE income to cover taxes.[8] These make DTE capital spending dramatically more costly for customers than DTE O&M spending. When considering DTE's capital spending requests, the Commission cannot ignore the significant premium on DTE capital spending that customers pay relative to what customers pay on DTE O&M spending.

Q. Has DTE calculated the cost to customers of these large capital spending increases?

A. No. The Company has only estimated revenue requirements through the forward test year being employed in its application, ending December 31, 2025. The Company requests a $456 million increase in the revenue requirement to cover spending through December 31, 2025, driven largely by increases in capital spending and financing costs on that spending ($285 million in capital cost recovery and $36 million in increased financing costs).[9] This

[7] Ex A-14, Sch D1.

[8] Ex A-13, Sch C2.

[9] Foley Revised Direct at NTF-14.

amounts to an 8.2% rate increase[10] and does not include any of the capital spending increases described in the Company's 2023 Distribution Grid Plan in 2026, 2027, and 2028.

Q. Does DTE provide any context for these rate increases?

A. Yes. The Company reports that its average (residential) bills are below U.S. averages ($115 vs. $133).[11] This is a meaningless comparison that should be disregarded entirely. DTE appears to have derived it simply by dividing residential revenues by the count of residential customers. A myriad of differences are masked by this comparison, from customer loads and usage extents (think air conditioning in Florida vs. air conditioning in Michigan), to generation mix and fuel costs (think low-cost coal to higher-cost natural gas or renewables), to differences in the cost of living and the associated impact on the Company's labor rates (Michigan was recently reported as having the 12th lowest cost of living among U.S. states,[12] meaning DTE costs are likely lower than the U.S. average), and others. This bill comparison also disregards the fact that DTE's residential rates remain the highest among its Great Lakes peers and in the 4th quartile (highest) nationally.[13] The Commission should be unswayed by DTE's meaningless bill comparison.

Q. What is driving DTE capital spending increases?

[10] Ex. A-16, Schedule F2, p. 2.

[11] Foley Revised Direct at NTF-16, Figure 8 and note 5.

[12] Missouri Economic Research and Information Center. Accessed July 23, 2024, available at https://meric.mo.gov/data/cost-living-data-series.

[13] Ex MEC-2, Company Response to MNSCDE-2.5-22 Monthly Rate Benchmarking 2024_4_AprilvFinal (slide 3); 2.5-25 Spring 2023 Annual (slide 4)

A. Strategic capital programs amounting to 70% of Distribution Grid Plan spending 2022-2027 are presented in the table below. Note that almost all of the projects within these programs are discretionary as to timing and extent. This means that none are required to address equipment failures or equipment damage; or connect new customers; or accommodate near-term load increases; these costs are budgeted separately as base capital programs. Thus, considerable optionality exists as to the timing of these programs' deployment (and indeed, whether they are truly "needed" at all). Further, it is worth noting that most programs do not consist of individually-identified projects; in general, these are program-wide budgets the Company is asking the Commission to approve without regard to the circuit miles completed or units installed (prompting concerns over both cost control and the Company's reliability improvement estimates). Other than 4.8kV conversions, designed primarily to increase capacity to meet far-off load increases, strategic programs are generally intended to improve reliability. Whether they do so in a cost-effective manner is the issue. My colleague, AG-MNS witness Stephens, addresses in his testimony all the programs listed in the table below, together with a few others:[14]

	Application Detail				IRM	
Programs ($ in millions)	2022	2023	2024	2025	2026	2027
4.8kV Hardening	157.5	127.0	80.0	125.0	-	-
Pole & Pole Top Maint & Mod	83.9	79.1	63.5	121.0	150.0	200.0
Subtransmission Redesign & Rebuild	52.4	71.9	40.6	43.6	55.0	65.0
4.8kV Conversions to 13.2 kV	104.5	161.9	199.2	78.8	190.0	240.0
Distribution Automation	5.5	27.1	21.2	125.6	105.0	180.0
Totals	403.8	467.1	404.4	494.0	500.0	685.0

Q. But clearly, DTE needs to invest in the grid to improve reliability, does it not?

[14] Ex A-12 Sch B4.5 pp. 13, 16, 17; Ex A-33 Sch X1 (IRM).

A. Perhaps to some extent, but as noted above, strategic capital investment programs are discretionary as to amounts, geographic extent, and timing. Further, this question assumes that more capital investment will deliver reliability improvements of sufficient value to justify the spending. Neither independent research nor our (Mr. Stephens' and my) experience validates this assumption.

Mr. Stephens and I are particularly concerned about the difference in cost-effectiveness between vegetation management and capital spending at improving reliability. DTE's vegetation management "surge" and commitment to a five-year vegetation management cycle are laudable. But before knowing the system-wide reliability impact of these efforts, DTE is forging ahead with capital expenditures amounting to almost $4 billion dollars in 2023-2027 for discretionary "strategic capital" programs designed to improve reliability:[15]

2023	**2024**		**2025**		**2026**	**2027**
Rate Base	Rate Base	IRM	Rate Base	IRM	IRM	IRM
801,026	708,777	61,865	827,280	290,134	530,000	720,000

And much more on the horizon – the table below is from the 2023 Distribution Grid Plan, which also not capture the full extent of this spending spree:[16]

[15] Ex A-12 Sch B5.4 p. 1, line 22 (rate base 2023, 2024, 2025); Ex A-33 Sch X1 line 8 (IRM).

[16] Ex A-12 Sch B5.4, p. 1 (2023 DGP, Ex A-23 Sch M8 p. 162 of 274. As discussed in the 2023 DGP and by Mr. Stephens, DTE aspires to spend many billions more to convert the entire 4.8kV system to 13.2kV, among other programs.

Exhibit 11.0.1 Projected Distribution Grid Plan Investments

Category		$ Millions 2024	2025	2026	2027	2028	5-Year Total
Capital Investments ($ Millions)							
Base Capital	Emergent Replacements (Reactive Trouble and Storm Capital)	$415	$399	$368	$348	$345	$1,877
Base Capital	Customer Connections, Relocations and Others	$282	$295	$314	$334	$355	$1,580
Strategic Capital Programs (details in Exhibit 11.0.2)		$906	$995	$1,134	$1,302	$1,485	$5,821
Total Capital Investments		**$1,603**	**$1,689**	**$1,816**	**$1,985**	**$2,185**	**$9,278**
Maintenance Programs ($ Millions)							
Tree Trimming		$123	$140	$101	$103	$106	$573
Preventive Maintenance		$10	$10	$10	$10	$10	$50

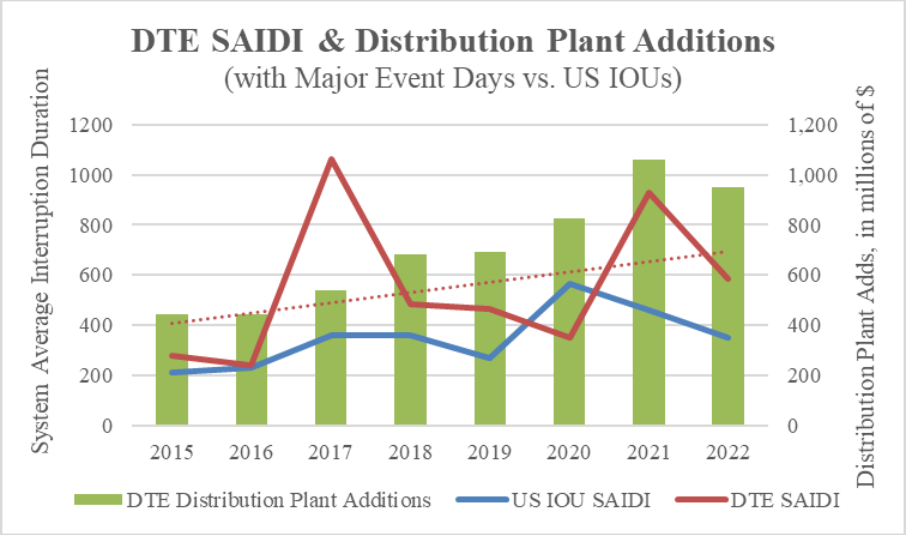
We urge the Commission to evaluate the success of the tree trimming modifications before concluding that massive capital spending is required to improve reliability.

Research completed by Lawrence Berkeley National Laboratory on behalf of the U.S. Department of Energy found no correlation between investor-owned utility distribution capital spending increases and reliability improvement the following year.[17] Regarding DTE's own experience, DTE admits that more frequent tree trimming – for the most part an O&M expense, not capital spending -- is the most effective thing DTE can do to improve reliability, stating "In areas where tree trimming has been completed,

[17] Larsen PH, LaCommare KH, Eto JH, and Sweeney JL. *Assessing Changes in the Reliability of the U.S. Electric Power System*. Lawrence Berkeley National Laboratory report LBNL-188741 (August 2015), pp. 37-38. Accessed July 22, 2024, available at: https://emp.lbl.gov/publications/assessing-changes-reliability-us.

communities have experienced, on average, 60% fewer outages."[18] Finally, the chart below indicates that despite a 214% increase in annual distribution grid capital spending from 2015 to 2022, DTE's service interruption frequency *increased* 58.1%, and is still worse than the average for U.S. investor-owned utilities. To date, DTE has not shown that massive increases in capital spending deliver reliability improvements.

Figure 1: DTE service interruption duration vs. distribution plant additions over time



Q. That result seems counter intuitive. How do you explain it?

A. The Company tends to describe distribution capital spending as the primary solution for improving reliability. For example, the 2023 Distribution Grid Plan states "much of the current infrastructure is at or beyond expected useful life and susceptible to failure, particularly when exposed to extreme weather."[19] This statement contains several

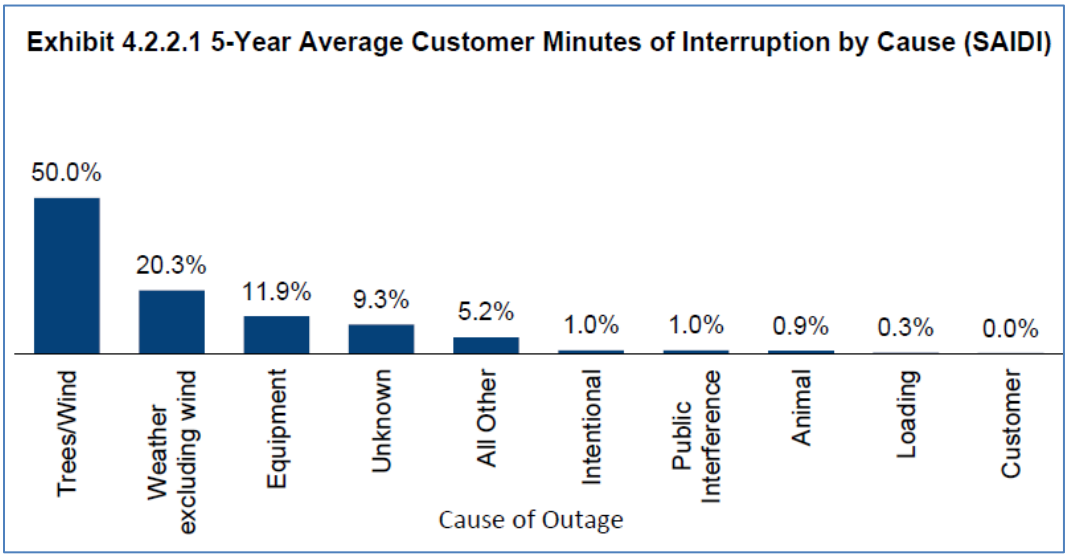
[18] *DTE Announces an additional $70 million investment to combat extreme weather-related power outages*. DTE Energy press release (September 1, 2021). Accessed July 22, 2024, available at https://ir.dteenergy.com/news/press-release-details/2021/DTE-announces-an-additional-70-million-investment-to-combat-extreme-weather-related-power-outages/default.aspx.

[19] Ex. A-23 Sch M8 (2023 DGP) at 54 of 274.

misleading statements. First, "expected useful life" is a reference to depreciation periods, which are based on the average age of assets in service (also known as "survivor curves"). Distribution equipment is removed from service for many reasons (capacity expansion, storm damage, facility relocations, and the like), meaning that the average age of equipment in service – while useful for depreciation period determination – should not be used as an expectation of an equipment's design life. For example, utility poles, though typically depreciated over 40 years, routinely provide safe and reliable service for 80 years or longer with sound inspection and maintenance practices. To decide that equipment should be replaced simply because it is fully depreciated, when decades of useful life might be remaining, serves shareholders at customers' expense.

An analysis of service interruption causes is also illustrative. In its Distribution Grid Plan, DTE reported that at least 50% of customer minutes of interruption are caused by vegetation contact, while less than 12% of customer minutes of interruption are associated with cause "equipment":[20]

[20] 2023 DTP, Ex A-23 Sch M8 Exhibit 4.2.2.1 at 41 of 274.



Further, my colleague Mr. Stephens reports that the equipment cause is overused by field personnel, thereby overstating "equipment" as a cause of service interruptions. In his examination of field notes the Company recorded on a random sample of 100 service interruptions classified as "equipment" related, only 67% of service interruptions with field notes sufficient to determine root cause could be traced to unprompted failures of equipment in service, while 33% were caused by vegetation contact or damage by third parties. Thus, attributing even 12% of the Company's customer minutes interrupted to "equipment" overstates the equipment condition "problem".

Finally, I note that some DTE strategic capital programs, like Distribution Automation, are designed to mitigate the impact of service interruptions rather than address the root causes of service interruptions. Given that vegetation contact is the root cause of at least 50% of the interruption minutes customers experience, spending should be focused on root causes, not symptoms. To summarize, tree trimming, and not capital spending, is the most cost-effective way to improve reliability.

Q. But what of DTE's projected reliability improvement benefits?

A. Later, I will describe fundamental problems with the way DTE has calculated the reliability improvements attributable to its strategic capital programs. Specifically, the way DTE defined its control group circuits (used as a baseline for comparison with circuits to which capital programs have been applied) dramatically overstates the benefits DTE's Reliability Model projects. The Commission should not rely upon reliability improvement projections from DTE's Model when considering DTE's strategic capital spending proposals.

Q. How do you think the Commission should consider Michigan's Healthy Climate Plan and related legislation when evaluating the Company's Application?

A. Michigan's Healthy Climate Plan does not require large, immediate increases in distribution spending. With respect to electric vehicles, about 95% of electric vehicle charging for customers on time-of-use rates is off-peak.[21] (Time-of-use rates offer EV owners the lowest charging costs.) Therefore, preparing the grid for electrification, for example through conversion of 4.8kV circuits to 13.2 kV, does not appear to be an urgent need. The Commission may also be interested to note the Healthy Climate Plan's focus on affordability, targeting a maximum 6% energy burden for low-income households.[22]

The Michigan Legislature has taken some action on the Healthy Climate Plan, including the Clean Energy Future Package. The Package enhanced rooftop solar

[21] Fitch T, Frost J, and Whited M. *Electric Vehicles Are Driving Electric Rates Down*. Update of a study completed by Synapse Energy Economics for the Natural Resources Defense Council (June, 2020), Fig 3, p. 3. Accessed July 22, 2024, available at https://www.synapse-energy.com/sites/default/files/EV_Impacts_June_2020_18-122.pdf.

[22] *MI Healthy Climate Plan*, Michigan Department of Environment, Great Lakes, and Energy (April2022), p. 36.

deployment in Michigan, though in our (Mr. Stephens' and my) experience rooftop solar does not typically require much distribution grid investment. Only utility-scale, rurally located solar systems typically require significant distribution grid investment, and these cannot typically be forecast in advance of developer applications. Further, many of these systems are interconnected to the transmission grid, not distribution. The Clean Energy Jobs Act further facilitated utility-scale wind and solar development, but again, the opportunities to prepare the distribution grid in advance for these are almost non-existent. In summary, while the Healthy Climate Plan and clean energy legislation are important policy changes in Michigan, their impacts on distribution grid investment needs appear minimal for the near-term.

Q. What do DTE's customers think about ever-increasing DTE rates?

A. Customers obviously dislike rate increases, but comments from DTE customers reveal specific frustration regarding the lack of value customers are receiving in exchange for DTE rate increases. Many customers also express frustration with the Commission. We encourage the Commission to pay particular attention to the following excerpts from written comments submitted by DTE customers on the Company's instant application:[23]

- "There is no transparency with DTE"
- "Do not provide DTE with more money to syphon off to the executives and shareholders under the false claim of improving the system."
- "I do not see that an increase will be spent wisely."
- "They keep asking for more money yet our electricity is always going out and our bill is higher than ever."
- "Can you really approve a rate hike for the lack of maintenance shown in these pics? These dead trees have been risking our power for years."

[23] Case No. U-21534, Case Comments,

- "What do we pay the Public Service Commission to do? We pay you to do your job. I'm sorry but many of us are feeling neglected!"
- "This is price gouging and you would be complicit in it if this request is approved."
- "Start looking out for the citizens of our state instead of just keep approving rate hikes so DTE can report larger profits like what has happened the last 2 years."
- "Please get realistic when you're considering caving, once again, to DTE."
- "They say that they're doing all this work but where is the proof who's looking into where the money is going?"
- "They are going to raise our rates with the promise of stabilizing the grid, having fewer and shorter outages, etc. But if/when that doesn't happen, are they going to lower the rates again and reimburse everyone for the failed attempt? Absolutely not."
- "Please reject this proposal and make DTE do better with what they have."
- "Michigan electricity utility service quality is in the bottom quarter of all states in most quality metrics, per the Citizens Utility Board of Michigan."
- "When it comes to what DTE says I do not believe what they say any more."
- "Why should we pay more for a unreliable service."
- "DO NOT grant them another rate increase until they can prove for several years consecutively that they indeed deserve more of OUR hard earned money."
- "I am against the DTE price increase. For years they have neglected the grid and maintenance of lines for the profit of their investors."
- "It is absolutely criminal that DTE can year after year request rate hike after rate hike and my…our service had not improved whatsoever. Just recently as last month I sat here with no power trying to report it to DTE and all they did was tell me that my power was on. It was absolutely infuriating."[24]
- "I would urge the commission to fulfill its duty to the public, deny the rate increase, and remember who they're supposed to serve."

[24] This comment indicates that the meter associated with this customer's premises in DTE records is actually installed on some other customer's premises (with its power on). This means that this customer is paying for the electricity used at that other customer's premises, and that some other customer is paying for the electricity used at this customer's premises. This error probably occurred during DTE's deployment of smart meters, and causes me concern as to how widespread this problem is among DTE customers.

Q. What are your context and perspective conclusions?

A. While the Commission's focus on improving the reliability performance of DTE and other electric distribution utilities is appropriate, capital spending is not necessarily the most cost-effective way to satisfy reliability objectives. The Commission appears under pressure to improve reliability, but also to identify the most cost-effective ways to do so. Given the size of capital spending increases ostensibly proposed to improve reliability, DTE's implied assumption that massive investment is required to improve reliability must be rigorously evaluated. My overall recommendation, consistent with that of my colleague, Mr. Stephens, is that the Commission require DTE to slow down the capital spending locomotive that it has become. Further, before speeding up the locomotive again, I recommend the Commission require DTE to collect and provide more data on the reliability improvement value of enhanced vegetation management vs. improvements from strategic capital programs; strengthen its capital spending governance; and practice capital budgeting restraint. These themes are further developed throughout the rest of this testimony.

III. THE COMMISSION SHOULD INCREASE CAPITAL SPENDING GOVERNANCE AND REJECT THE COMPANY'S REQUEST TO EXTEND AND EXPAND THE IRM

Q. Please preview this section of testimony.

A. In this section of testimony, I describe the critical processes of capital spending governance and identify shortcomings in these components at DTE. I also explain the unintended consequences associated with rider cost recovery such as DTE's Infrastructure Recovery Mechanism ("IRM"), and the increased need for capital spending governance that results.

I conclude with a recommendation that the Commission reject the Company's request to extend and expand the IRM.

A. Critical Processes for Capital Spending Governance

Q. What are the critical components of capital spending governance?

A. In my experience there are three processes critical to sound capital spending governance. To adequately govern capital spending and maximize value per dollar invested, all three processes must be actively and rigorously managed:

- Capital project/strategic program selection and capital budget development;
- Capital project/strategic program planning and cost tracking; and
- Capital project/strategic program performance evaluation.

Q. Please explain capital project/strategic program selection and capital budget development.

A. Capital project/strategic program selection and capital budget development is all about decision-making. Though some utility capital spending is not discretionary, all of DTE's strategic capital programs offer optionality as to geographic extent (which circuits are most likely to deliver benefits in excess of costs) and speed of deployment. When contemplating whether to fund a strategic program, for which geographies, and at what deployment speed, it is important to establish expectations for benefits relative to costs, such as in a benefit-cost analysis.

Companies competing in unregulated markets are extremely good at managing to capital budget constraints, because market prices for the companies' products and services restrict the amount of capital such companies can spend. These companies, including

almost all of DTE's commercial and industrial ("C & I") customers, must carefully choose how to spend their limited capital. For for-profit monopolies regulated by state utility regulators, regulation represents the only limit to capital spending. Because regulators offer utilities an opportunity to earn a return on invested capital (earnings, also known as profits), utilities are motivated to spend as much capital as they can to increase earnings. This incentive is known as "capital bias".[25] In my experience, utilities are only as good at restraining the size of capital budgets, and therefore project/program selection, as their regulators force them to be.

Q. Please explain capital project/strategic program planning and cost tracking.

A. Project/strategic program planning and cost tracking is all about cost control. For projects, this means establishing a plan and budget for executing each project, managing project execution in a timely manner, and tracking the capital expended to complete the project. Most utilities are reasonably good at this. For strategic programs, this means establishing some type of program expectations, such as the number of circuit miles to be completed, or units to be installed, for the capital budget established. In my experience utilities are not good at this.

Q. Please explain capital project/strategic program performance evaluation.

A. Project/strategic program performance evaluation is all about accountability. For projects, this is generally a post-completion evaluation that examines whether a project was placed into service by the time indicated and for the costs budgeted in the project plan. Any

[25] Averch H and Johnson L. *Behavior of the Firm Under Regulatory Constraint*. The American Economic Review, Vol. 52, No. 5 (Dec., 1962), pp. 1052-1069. Accessed July 22, 2024, available at https://www.jstor.org/stable/1812181.

deficiencies identified in the post-completion evaluation are tracked back to root causes in project planning and execution, and improvements in company-wide project planning and project management processes are sometimes implemented as indicated.

For programs, performance valuation constitutes a check-in on the components of the program as they are completed. This involves, for example, whether miles completed or units installed for the budget established matched expectations. It also involves a determination as to whether the benefits delivered by the program are as large as anticipated by utility management upon program approval. In my experience, utilities are not only abysmal at this, they have no incentive to validate program performance.

B. Shortcomings in capital spending governance at DTE

Q. Is DTE deficient in its capital project/strategic program selection and capital budget development?

A. Yes. DTE selects projects and strategic programs for its capital budget using its *Global Prioritization Model*. I provided extensive critique of DTE's Global Prioritization Model ("GPM") in my testimony in DTE's last rate case and will repeat those critiques later in this testimony. But for now, the salient point is that the GPM does not determine capital budget size, or the speed at which strategic programs are implemented. These decisions are made by DTE management, hired by DTE shareholders to maximize shareholder value. Due to capital bias, DTE shareholder value is maximized when earnings grow, and opportunities to grow earnings increase with the size of capital budgets (rate base increases). As a result, the size of the Company's capital budget, absent regulatory control, is constrained only by 1) how fast DTE can spend capital; and 2) how much capital DTE

can raise. This is not conducive to sound capital spending governance, and utility regulation has evolved to serve as constraint on capital spending in the absence of the capital spending discipline that would normally be instilled through competitive pressure.

Q. Is DTE deficient in its capital project/strategic program planning and cost tracking?

A. For defined capital projects, DTE does not appear to be deficient. It appears to have processes for planning capital projects, estimating projects costs, securing management approval, managing project execution, and tracking projects costs. However, for some of DTE's largest strategic capital programs, DTE planning and cost tracking appear to be extremely deficient.

The Company's Pole and Pole Top Management and Modernization ("PTMM"), 4.8kV circuit hardening, and Distribution Automation (DA) programs appear to be managed only at the program level as opposed to project level.[26] The annual 4.8kV circuit conversion budget likewise appear to be a large pot of money from which DTE's distribution team can use to fund various conversion projects (though better defined) at will.[27] We could find no established expectations for counts of circuit miles or DA device installations to be completed for the budgets established for these programs. Apparently, budgets are established annually for these programs,[28] but there is no telling exactly how many circuit miles customers can expect will be completed, or DA devices customers can

[26] See Company responses to MNSCDE 8.15(b) ("The Company budgets and manages the 4.8kV Hardening Program at the program level), 8.16(b) ("The Company budgets and manages the PTMM Program at the program level."); and 8.19(a).

[27] Company response to MNSCDE 8.18(d)(i).

[28] Ex MEC-5, Company response to MNSCDE-8.5c(S1)-02 2023 Budget Appropriation, line 47.

expect will be installed, or the capacity or reliability improvements that will be achieved, for the established annual budgets for these programs.

Q. Does this present a challenge for the performance evaluation component of capital spending governance?

A. Yes, absolutely. If there is no expectation as to the count of miles or devices installed for the established budgets, there will be no way to track or manage program spending relative to expectations. Further, program benefit projections can be over-estimated.

Take the PTMM program, for example, which had a program budget of $127 million in 2023.[29] The Company reports the PTMM budget was for 92 circuits in 2023.[30] Was PTMM intended to be completed on the entirety of each circuit, or just parts? Did the amount of PTMM work completed in 2023 for $127 million meet expectations, or did customers get less PTMM than the Company expected to deliver for $127 million? If there is no expectation, there is no poor performance or good performance relative to budget. There is only a record of how much money was spent on the program as a whole, which means nothing without a measurement of units to compare to.

Further, the Company's benefit projections for these programs are likely overstated. If the benefit projected was based on an assumption that the $127 million budget would complete 150 miles of PTMM, but only 95 miles of PTMM were actually completed for $127 million, customers will clearly not receive the reliability improvements per dollar anticipated. But as it stands, we cannot even determine how many circuit miles of PTMM

[29] Ibid, Line 47.

[30] Ex MEC-6, Company response to MNSCDE-8.16(d)(i).

should have been completed for $127 million, let alone the reliability improvement benefits customers should have received for $127 million.

C. Unintended Consequences of Rider Cost Recovery (such as DTE's IRM).

Q. Does the relatively poor capital spending governance at DTE, particularly for large strategic programs, have implications for the use of riders for cost recovery?

A. Yes. Rider cost recovery increases the need for strong capital spending governance. Rider cost recovery shifts capital spending risk from shareholders to customers, shifts prudence responsibilities from utilities to intervenors, and introduces moral hazard into utility distribution grid investment plan development. I discussed these unintended consequences at length in my testimony in U-21297,[31] and so I will address them more briefly in this testimony. But the bottom line is that rider cost recovery (and for the same reasons, even forward test year ratemaking) marks fundamental changes in the balance of interests between shareholders and customers that for-profit monopoly utility regulation was developed to maintain. The Commission should recognize these changes as important context in evaluating DTE's request to extend and expand rider IRM.

Q. How does rider cost recovery shift capital spending risk from shareholders to customers?

A. Once the Commission approves an amount of capital spending for a rider like IRM, the Commission's practical ability to order a cost disallowance falls to almost zero (for anything other than gross negligence or malfeasance). This is because any attempt to identify and then disallow cost recovery after the money was spent would be met with the

[31] Case No. U-21297, Direct Testimony of Paul J. Alvarez, 6 TR 3332-41.

utility argument that the Commission pre-approved the capital spend, and raises retroactive ratemaking concerns, which can be difficult for a regulator to reject. Further, if the Commission were to disallow large costs for recovery, such as the $127 million DTE spent in 2023 on the PTMM program, DTE's cost of capital would increase. Customers cover DTE's cost of capital in rates, countering the impact of a cost disallowance in any event. To summarize, once the Commission approves a rider of specific dollars in future years, its practical ability to disallow recovery of the cost of projects included in that spending falls almost to zero. I suspect that utilities recognize this, and act accordingly by proposing capital in a rider plan they would not otherwise spend under traditional ratemaking.

Q. How does this impact intervenors?

A. Rider cost recovery (like forward test year ratemaking) shifts the burden of proving prudence from utilities (in traditional ratemaking, after the capital is spent) to intervenors, who must now prove imprudence when capital spending projects and programs are initially proposed. In traditional ratemaking, intervenors could rely on cost disallowance risk to reduce their prudence burden, because the threat of a disallowance would encourage capital spending restraint on the part of utilities. In rider (and projected test year) cost recovery, since regulators' practical ability to order a disallowance post-spending has fallen, utilities are encouraged to pursue much riskier capital projects and programs than they would actually spend capital on under traditional ratemaking. Thus, not only has the prudence burden shifted from utilities to intervenors, the amount of capital spending and the number of projects and programs intervenors must review and challenge goes up.

Correspondingly, because intervenors have historically been able to rely on cost disallowance risk to moderate utility capital spending, intervenors' need for technical expertise to challenge the prudence of capital spending has historically been lower. With rider cost recovery, intervenors must retain technical experts like myself and Mr. Stephens to challenge the appropriateness of capital projects and programs proposed for rider cost recovery in advance of capital spending, and information asymmetry makes it difficult for intervenors' experts to gather the data needed to evaluate utility spending proposals.

Q. You mentioned that under rider cost recovery, utilities are encouraged to propose much riskier capital projects and programs than they would actually spend capital on under traditional ratemaking. Can you further explain this?

A. Under traditional ratemaking, when utilities face cost disallowance risk, they are careful not to spend capital on projects or programs at a high risk of cost disallowance, due to the financial penalties to utilities associated with cost disallowances. Under rider cost recovery, due to the reduction in regulators' practical ability to order disallowances described above, utilities have nothing to lose, and everything to gain, by proposing more capital spending than they would otherwise spend under traditional ratemaking. If a regulator rejects a capital project or program a utility proposes for rider cost recovery, the financial penalty to a utility is zero. This is very different from the financial penalties associated with disallowances of recovery on costs already incurred. Economists call this *moral hazard.* Rider cost recovery, and the moral hazard it introduces into capital spending plan development, is the opposite of capital spending constraint.

Q. Do you have any evidence that riders like IRM discourage capital spending governance?

A. An exercise to examine rider cost recovery in every state would be time-prohibitive, but Michigan- and DTE-specific evidence is available. In his testimony in DTE's current gas rate case, U-21291, AG Witness Mr. Coppola identifies massive increases in DTE's gas main replacement program once rider IRM was approved by the Commission. What began as a $17.4 million program in 2012 increased to a massive $350 million program proposed by 2023.[32] More importantly, DTE's proposal in this proceeding to double the IRM period and more than quadruple IRM spending relative to what the Commission approved in U-21297 epitomizes the moral hazard riders introduce into utility investment planning.[33]

Q. To summarize, capital spending governance is important in for-profit utility regulation, and rider cost recovery is the antithesis of capital spending governance?

A. Precisely. Rider cost recovery 1) reduces regulators' practical ability to disallow recovery of capital spending previously approved for a rider; 2) shifts the burden of prudence from utilities to intervenors; and 3) introduces moral hazard into utility capital budget development. The end result is a shift in capital spending risk from shareholders to customers. For these reasons, I recommend the Commission reject DTE's request to extend and expand rider IRM.

[32] Case No. U-21291, Direct Testimony of Sebastian Coppola, 4 TR 1453-54.

[33] Revised Foley Direct at NTF-54 Table 1; Ex A-33 Sch X1.

Q. Don't the procedural mechanisms the Commission has imposed on DTE's IRM do enough to offset your concerns related to excessive capital spending burden-shifting?

A. No, they do not. In U-21297, the Commission required DTE to notify Staff and intervenors about their IRM plans, with an opportunity for questions, and required a contested reconciliation proceeding.[34] These two procedural mechanism – the preview and reconciliation – offer little more than lip service to capital spending governance. Since the Commission set a cap on spending, providing intervenors with a list of planned projects up to the authorized IRM spending level conceivably *might* allow participating intervenors with technical expertise to advocate for shifted projects – *e.g.*, start PTMM on a particular circuit sooner – but changes seem unlikely (DTE is unlikely to shift course so close to start of the IRM year). Moreover, the preview process still leaves the burden on the intervenors to counter DTE's plan, not the other way around. The reconciliation contested proceeding is similarly unredeeming – the money will already have been spent. DTE is asking the Commission to approve an IRM that adds two more years and another nearly $1 billion in distribution capital spending in 2026 and 2027, even before the first IRM year is completed. Mr. Stephens addresses the weak foundations for the strategic capital programs DTE proposes for IRM cost recovery, but even if the foundations were solid, the Commission should reject rider expansion and extension for the reasons discussed above.

[34] Case No. U-21297, Dec. 1, 2023, Order, pp. 289-90.

IV. THE COMMISSION SHOULD REJECT VEGETATION MANAGEMENT COST CAPITALIZATION (EXCEPTING SURGE SECURITIZATION) AND OTHER ETTP PROPOSALS AND ESTABLISH REPORTING AND AUDITING TO ENSURE ETTP BENEFITS ARE RETAINED.

Q. Please preview this section of testimony.

A. This section of testimony addresses the Company's vegetation management proposals. It will begin with some background on vegetation management generally, and briefly cover the history and current state of vegetation management practices at DTE. It will proceed by summarizing DTE's proposals to increase O&M and regulatory asset spending to complete the Enhanced Tree Trimming Program ("ETTP") Surge, and to earn a return on the Surge regulatory asset while it awaits securitization. It will conclude with recommendations regarding DTE's capitalization of vegetation management expenses; recommendations to reject the Company's request to earn a return on the Surge regulatory asset; and a recommendation to order an overhead line right-of-way status audit to be completed every five years, beginning in 2025 or 2026.

Q. What kind of background on vegetation management would you care to provide?

A. When vegetation comes into contact with an overhead conductor, it creates a ground fault. As the nearest upstream protective device opens to isolate the fault, an associated service interruption occurs. The need to prevent vegetation from coming into contact with overhead conductor is as old as the industry itself, dating back to the introduction of alternating current, and the lines of conductor required to distribute that current, at the Chicago World's Fair in 1893. Vegetation management has always been one of the largest expenses most utilities must incur. It is characterized by its recurring and incessant nature. It was therefore no surprise that vegetation management was categorized as an operations

and maintenance expense when the Federal Energy Regulatory Commission first introduced the Uniform System of Accounts.[35]

Q. Does the Uniform System of Accounts permit capitalization of tree trimming expense?

A. Only in the specific circumstance of installing new facilities. (Electric Distribution Plant) Account 365, Overhead conductors and devices states: "Tree trimming, initial cost, including the cost of permits therefore."[36] While the term "initial cost" is somewhat ambiguous, this ambiguity is cleared by USOA Electric Plant Instruction No. 9, which states that Plant "*Also include those costs incurred in connection with the first clearing and grading of land and rights-of-way*."[37]

Q. Has the State of Michigan adopted the federal Uniform System of Accounts?

A. Yes. The Michigan Administrative Code R.460.9002 states "The federal uniform system of accounts for major and nonmajor electric utilities promulgated by the United States federal energy regulatory commission and codified at 18 CFR Part 101, as amended through April 1, 2010, is adopted by reference in these rules as of January 1, 2011. The rules are prescribed for the use of all electric utilities under the jurisdiction of the Michigan public service commission . . . unless otherwise ordered by the Michigan public service commission . . . ." The latter part of the Rule quoted provides the Commission with the ability to interpret, clarify, or strengthen the Rule as it deems appropriate.

[35] U.S. CFR Title 18, Chapter I, Subchapter C, Part 101, "UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED FOR PUBLIC UTILITIES AND LICENSEES SUBJECT TO THE PROVISIONS OF THE FEDERAL POWER ACT. Account 593, Maintenance of overhead lines, Account 593, Part 2.k, "Tree trimming and brush clearing".

[36] Ibid, Electric Distribution Plant Account 365.

[37] Ibid, Electric Plant Instructions, "9. Equipment", part A.

Q. Has the Commission been asked to interpret the Uniform System of Accounts with respect to vegetation management accounting?

A. Yes. In the DTE general rate case U-17767, the issue was raised in response to DTE's request to capitalize its new Enhanced Vegetation Management Program (which has since been renamed the Enhanced Tree Trimming Program, or "ETTP"). In this former proceeding, DTE claimed that the more rigorous trimming standard was in effect "a second initial clearing" of right-of-way because the first clearing was not performed to the new specification. That interpretation was firmly rejected by the Commission Staff's engineering specialist Peter Derkos.[38] The ALJ, and subsequently the Commission in its U-17767 order, agreed with Staff regarding the interpretation of the Michigan USOA, that the new (ETTP) program is not a first clearing of rights-of-way, and thus is properly an operation and maintenance expense.[39] Specifically, the Order states "…the Commission is not persuaded that this cost category is appropriate for capitalization." "The EVMP effort is not a first clearing, because all of these ROW's have been cleared before, possibly multiple times…. Having rejected capitalization treatment, the amount of allowed expense is addressed under net operating income."

Q. What do you conclude regarding the capitalization of vegetation management spending?

[38] Case No. U-17767, Direct Testimony of Peter Derkos, 8 TR 2088.

[39] Case No. U-17767, Oct. 8, 2015, PFD, pp. 86-87, Dec. 11, 2015, Order, pp. 25-27.

A. I conclude that the only permitted capitalization of vegetation management spending is in the initial construction of a brand-new overhead distribution line. Any other capitalization of tree trimming expense is an unequivocal violation of the Michigan USOA.

Q. Does DTE capitalize vegetation management spending for reasons other than initial construction of a brand-new overhead distribution line?

A. Yes. DTE seems to have adopted the policy that if vegetation management is required to complete the work of a capitalized project, the vegetation management spending associated with the project is capitalized as well.[40] Depending on last trim date and the scope of work, extensive if not total trimming of trees is undertaken for projects completed under the 4.8kV hardening, 4.8kV conversion programs, PTMM, and Distribution Automation. As each of these programs involves dozens of miles of circuit work annually, the amount of vegetation management spending the Company is capitalizing annually through these programs is significant:[41]

Program	2022 Capital Investment	2023 Capital Investment	Total
4.8kV Hardening	$34.6	$18.40	**$53.0**
4.8kV Conversions	$0.4	$2.10	**$2.50**
PTMM	$8.8	$9.30	**$18.10**
Distribution Automation	$0	$0.17	**$0.17**
Total	**$43.80**	**$29.97**	**$73.77**

Q. Has the Commission considered DTE's practice of capitalizing tree trimming associated with the hardening, conversion, and PTMM programs?

[40] Ex MEC-3, Company response to MNSCDE-15.25d, e, f.

[41] Ex MEC-3, Company Response to MNSCDE-15.25g, h.

Y. Yes. In U-21297, the Commission determined that it would be better to evaluate this issue after the audit of the company's practice is complete, which is expected later in 2024.[42] The Commission adopted the ALJ's recommendation on this topic: "While this PFD recognizes DTE's incentives to capitalize rather than expense tree-trimming, it appears the company's accounting practice has been ongoing for a while. With the impending audit, this PFD concludes that it is preferable to await the audit results. In the meantime, DTE should be reminded that it needs to retain records to establish the legitimacy of its choices."[43]

Q. What are your recommendations to the Commission regarding DTE's capitalization of vegetation management spending associated with these strategic capital programs?

A. With respect to the tree trimming costs capitalized as part of the PTMM, 4.8kV Hardening, 4.8kV Conversion, and Distribution Automation programs (including spending through the IRM), I recommend the Commission:

- Require DTE in its next rate case to identify the extent that it capitalized tree trimming costs in each program, each year, from 2021 through 2024;
- Require DTE to present in its next rate case an analysis of the full costs to ratepayers resulting from its decision to capitalize tree trimming costs compared to the cost of on-cycle maintenance O&M trimming; and
- Require DTE in its next rate case to explain the legitimacy of its decision to capitalize tree trimming expenses for distribution capital programs.

[42] Case No. U-21297, Order, p. 281; Foley Revised Direct at NTF-60.

[43] Case No. U-21297, Oct. 5, 2023, PFD, p. 701.

Q. What are your impressions of DTE's Enhanced Tree Trimming Program and Surge?

A. ETTP was clearly necessary, and the Commission rightly required DTE to securitize Surge costs and deny DTE shareholders a rate of return on those costs. It is clear to Mr. Stephens and I that DTE's poor reliability performance in recent decades, including several major storm incidents accompanied by weeks-long service interruptions for thousands of customers, has been caused in large part by DTE's apparently frequent decisions to defer scheduled and budgeted tree trimming to future years. Given that cost-of-service ratemaking provides utilities with an economic incentive to reduce Operations and Maintenance spending between rate cases, and given the large size of annual vegetation management budgets, the temptation to defer vegetation management spending to hit earnings targets promised to Wall Street may be difficult for utility executive teams to resist. But compounded over years, the impact of DTE's deferrals on the service reliability customers experience is clearly significant and should not have been tolerated by previous Commissions.

Notwithstanding those deferrals, the responsibility to remedy the problem, and to ensure it does not arise again, is clearly owned by the current DTE executive team and Commission. Shareholders have benefitted for so many years at customers' expense, and this Commission should seize every opportunity available to restore the balance between shareholder and customer interest that for-profit monopoly regulation is intended to maintain.

Q. Have you reviewed Mr. Lepczyk's proposal for DTE to earn a return for shareholders on the Company's ETTP Surge Regulatory Asset?

A. Yes. I understand that securitization, like any bond or equity offering, entails significant fixed costs, and that customer costs can be reduced through the use of fewer, larger-sized securitization events. I also understand that between securitization events, the associated regulatory asset used to track Surge costs can get quite large.

On the other hand, it is clear that shareholders have reaped the rewards of increased earnings as DTE decisions to defer scheduled tree trimming were made year after year. It is even clearer that customers have paid the price for DTE's decisions to defer scheduled tree trimming through poor reliability performance, and that DTE is now using its poor reliability performance to justify massive and growing strategic capital spending. Customer frustration with the disconnect between large increases and poor reliability performance, as indicated by the excerpts from customer comments presented earlier, is palpable.

Q. What is your recommendation regarding the Company's request to earn a shareholder return on the Surge regulatory asset?

A. The regulatory compact provides the Commission with guidance on this DTE proposal. Under the compact, the state awards a monopoly for a defined service area. In exchange, the utility agrees to provide non-discriminatory service to all customers in that service area who request it and to make the investments necessary to provide that service in a safe and reliable manner. To compensate the utility for raising and investing capital and taking risk, the state offers the utility an opportunity to earn a fair rate of return on used and useful invested capital. The monopoly award continues at the option of the state, which controls the utility's rates.

The state of Michigan, in the form of the Commission, has upheld its end of the compact. The Commission has continued to award DTE an electric distribution monopoly, and a fair opportunity to earn a rate of return on invested capital, since 1909, when the Michigan Legislator first authorized the Commission to regulate electric utilities. However, by continuing to defer scheduled tree trimming year after year, DTE appears to have taken advantage of the state-awarded monopoly. Shareholders benefitted at customer expense from deferred tree trimming. By authorizing a rate of return on the Surge regulatory asset the Commission would be rewarding the Company for the poor and self-interested tree trimming deferral decisions the Company has made in the past. As the need for the ETTP Surge was a problem of DTE's own making, providing such a reward would be inappropriate.

Further, the provision of a return for shareholders on the Surge regulatory asset, when no such return is provided on securitized loans (at present), results in an economic incentive to make the Surge regulatory asset as large as possible. One way the Company might increase the size of the regulatory asset would be to delay securitization events. This would not be in customer's interest, as DTE's weighted average cost of capital (including profits for shareholders), plus income taxes on regulatory asset profits customers must pay, results in much higher costs for customers on the regulatory asset relative to the cost of the securitized loans. My recommendation is that the Commission reject the Company's request to earn a return for shareholders on the Surge regulatory asset, thereby negating the

Company's incentive to increase the size of the regulatory asset and remaining consistent with the Commission's treatment of this regulatory asset in prior cases.[44]

Q. Now that the company is reaching the end of its ETTP Surge, what should the Company do to maintain a five-year vegetation management?

A.

A. It is critical that the Commission ensure DTE not resume its historic pattern of deferring tree trimming, and the Commission should institute regulatory guardrails to ensure that outcome. My first recommendation is that the Commission order DTE to continue its annual public report of tree trimming that it initiated in U-20162.[45] The annual report provides valuable public information about spending, miles cleared, and reliability performance.[46]

My second recommendation is that the Commission institute a periodic audit of the actual state of the Company's overhead rights of way. There are many reasons for the Commission to institute a periodic audit of the actual state of the Company's overhead rights of way. First, maintaining the Company's rights of way has been shown to be one of the most critical drivers of DTE's reliability performance. Second, the Company's incentive to increase earnings by deferring scheduled vegetation management will remain once the Surge is complete. Third, the Company has demonstrated an inability to resist vegetation management deferral in the past. Fourth, the impact of such deferrals is difficult

[44] *See, e.g.,* Case No. U-21297, Dec. 1, 2023, Order, p. 280.

[45] Case No. U-20162, May 2, 2019, Order, pp. 80-81.

[46] Ex MEC-4, March 1. 2024, DTE Tree Trim Annual Report.

to detect immediately, as reliability deterioration only becomes apparent after years of such deferrals. Fifth, it is difficult for intervenors to ascertain the state of the Company's overhead rights of way. Sixth, there can be variation in compliance with right-of-way distance clearing compliance among various contractors and crews. Seventh, vegetation management is completed under a variety of Company programs (4.8kV conversions, 4.8kV hardening, and PTMM), and it could be difficult to track the effectiveness of these relative to routine tree clearing cycle work. Eighth, the Company is proposing new approaches to vegetation management in the future,[47] and it will be important to make an objective determination as to how those new approaches fare relative to existing best practices.

Q. What would such an audit look like?

A. I recommend that a right-of-way audit be conducted once every five years by an independent expert, preferably retained and managed by Staff, with procurement processes open to intervenor participation. The audit would be designed around a set of circuits or circuit miles selected at random. The sample size should be statistically significant relative to total overhead line miles. The audit would measure the average line clearances along each circuit or line mile selected for the sample. The first audit would determine whether the Surge has been completed and could also serve as the baseline result against which future audit results could be compared. The end of the Surge presents a unique opportunity to establish such baselines that I recommend the Commission not miss. I therefore recommend the first audit be completed in 2025, or 2026 at the latest. The expert should

[47] Direct Testimony of Rachel C. Steudel, RCS-27 through RCS-32.

make recommendations regarding the sufficiency of the width of the rights of way the Company has defined for its ETTP.

V. DTE'S GLOBAL (PROJECT) PRIORITIZATION AND RELIABILITY (IMPROVEMENT PROJECTION) MODELS ARE UNRELIABLE

Q. Please preview this section of testimony.

A. This section critiques two models critical to the capital budgets DTE presents for approval in the instant application. The Global Prioritization Model prioritizes projects and program spending in the Company's capital budgets, but does so in an unreliable manner. DTE uses its Reliability Model to project system-wide reliability improvements from several large strategic capital programs, including ETTP, 4.8kV Hardening, PTMM, 4.8kV circuit conversions, and Distribution Automation. It uses these projections to justify the levels of spending proposed for these programs in the instant application. The Commission should not rely upon these projections to determine the appropriate level of spending for these programs.

A. <u>DTE's Global Prioritization Model is unreliable as to both outputs and Model application</u>

Q. What are your concerns regarding DTE's Global Prioritization Model?

A. It is appropriate for DTE to prioritize its capital spending in a way that reduces risks, such as risks to reliability and safety, from greatest to smallest. Some investments utilities make are required, such as investments to connect new customers within its defined service area, or to replace damaged or failed equipment, or to expand capacity when load forecasts indicate equipment ratings will be exceeded in the near term. There is no need to prioritize

these investments, or to complete benefit-cost analyses on such investments, because there is no option to avoid or defer such investments. But all other investments utilities make are discretionary, providing optionality as to whether to spend, how much to spend, where to spend, and over what time frames (how fast) to spend.

DTE's strategic capital programs are all discretionary as to whether to spend, how much to spend, where to spend, and over what time frames. As Mr. Stephens's testimony points out, there are important questions to be answered when making decisions about discretionary investments. These include: 1) Do the benefits to customers from the project or program exceed the program's costs to customers? 2) For programs, what is the optimum geographic extent of deployment (i.e., on which circuits or in what circumstances are the benefits most likely to deliver benefits in excess of costs)? and 3) For programs, what is the optimum timing/deployment speed? The Company's GPM does not address any of these questions.

Q. If DTE's GPM does not answer these questions, what does it do?

A. DTE's GPM model purports to rank capital projects and programs based on their ability to reduce risk, from highest to lowest. However, in Mr. Stephens's and my estimation, it does so in a very unreliable manner, for at least three reasons. First, DTE's Global Prioritization Model (GPM) assigns risk reduction values (scores) to projects and programs that are based in largest part on inputs subjectively assessed by employees. The model calculates a risk score for each of ten "impact dimensions" (generally, different types of risk, such as safety, reliability, etc.). Some impact dimensions seem to overlap, and perhaps double-count a particular type of risk. For example, two dimensions are "overload relief" and "capacity relief"; three others are "major event risk", "SAIDI", and "SAIFI".

While multiple inputs are employed to calculate the risk score for each impact dimension, most of these inputs are not data-driven (i.e., based on historical experience, research, or pilot results), but based on subjective GPM user assessments. Further, there are no estimates for current-state risk to serve as a basis of comparison. This means there are no estimates of the existing likelihood of an adverse event, and no estimate of the size of such an event's consequences. These attributes are critical to determining the size of the risk being addressed by a project or program, which in turn indicates whether the risk is significant enough to warrant attention in the first place. Still further, risk reduction estimates (such as a projected reduction in customer minutes interrupted) are input with no indication of the scale of the reduction relative to current-state risk. For example, does a 100,000 minute reduction in customer minutes interrupted represent a 2% reduction from the baseline, or a 50% reduction from the baseline? In summary, the subjective inputs outweigh the data-driven inputs, making the model's outputs highly malleable, and even the data-oriented inputs (largely, risk reduction estimates) are suspect, and difficult to evaluate or place into context. A model user can get the GPM outputs he or she desires for a particular project or program simply by manipulating subjectively-assessed model inputs for the project or program.

Once impact dimension scores are calculated from inputs that are mostly subjective, weightings are applied. As examples, reliability scores are worth 50% more than the "Regulatory Compliance" scores, and the Regulatory Compliance scores (along with a few others, such as capacity relief) are worth double the cost avoidance scores (for O&M and capital). These weightings appear to be entirely subjective.

Q. What is your second concern about the GPM and the reliability of its outputs?

A. My second concern is that risk reduction value associated with projects and programs are scores, not dollars. Failure to express risk reduction value in dollars prohibits the completion of any kind of benefit-cost analysis for the projects and programs DTE recommends. Though the Company does compare the total risk score of a project or program to its costs, and uses this result to rank projects and programs, this is not a benefit-cost analysis. It indicates that project or program "A" might deliver more benefits per dollar than project or program "B", but the likelihood that either project will deliver greater customer value (in dollars) relative to customer costs (in dollars) is completely unknown. Remember, GPM is used to rank *discretionary* projects and programs. When determining whether to move forward with a discretionary project or program, the ratio of customer value (in dollars) to customer costs (in dollars) is the single most important question to answer.

Q. What is your third concern about the GPM?

A. Third, the GPM does not distinguish between discrete "projects" (such as a $7 million project to replace equipment at the Port Huron substation) and massive "programs" (such as the PTMM program, estimated at $715 million, or Distribution Automation, estimated at $1.162 billion, or 4.8kV hardening, at $259 million). Clearly, within these programs, application to some circuits will deliver greater benefits than application to other circuits. Thus, the GPM does not answer the other two questions critical for discretionary projects and programs: which circuits or circumstances warrant treatment, and over what time frames should these be completed?

Q. Do you have any other concerns about the GPM model or its application?

A. Yes, and it is a big one: DTE does not use the GPM model to score its Enhanced Tree Trimming Program or the associated Surge spending. If the GPM model were more reliable, and if the GPM model were to be applied to ETTP, Mr. Stephens and I are confident that ETTP and the associated Surge would rate a top priority program, far ahead of all the strategic capital programs.

Q. How would you summarize your concerns about DTE's GPM and its application?

A. I believe AG-MN summarized the GPM and its application succinctly in its Briefs in DTE's last rate case, and I note the Administrative Law Judge repeated AG-MNSC's summary in her proposal for decision:[48]

> "If I have a list of 10 possible purchases and I rank them from #1 through #10, that tells me what order to buy them in but it tells me nothing about whether to buy the first one of them, or the first three, or the first five, etc. Nor does it tell me how many of the purchases I can afford. Nor does it tell me which purchases will have more value to me than they will cost. Nor does it tell me whether to buy all of them over two years, or five years, or ten years. The GPM similarly tells DTE none of these things."

Q. What are your recommendations to the Commission regarding DTE's GPM?

A. I recommend the Commission avoid relying on the GPM or its outputs, and that the Commission question the manner in which DTE is applying the GPM. This recommendation is based on GPM's failure to adequately answer any of the questions critical to decision-making on discretionary programs – benefits (in dollars) relative to costs (in dollars); appropriate geographic extent; and appropriate speed of deployment.

[48] Case No. U-21297, Oct. 5, 2023, PFD, p. 188.

Q. How do you recommend DTE calculate the customer value of discretionary projects and programs?

A. Mr. Stephens and I recommend risk-informed benefit cost analyses be completed on all discretionary projects over a certain size (measured in capital dollars). The California Public Utilities Commission recently required risk-informed benefit cost analyses to be completed on all projects designed to improve reliability or safety.[49] The calculation for monetizing risk reduction benefits in dollars is presented below. Mr. Stephens and I recommend the reduction in the likelihood of an adverse event risk be estimated through the use of pilots, research, or historical experience, and that the consequences be estimated by circuit (in a reliability example, customer counts and likely service interruption durations associated with the adverse event a project is intended to mitigate.)

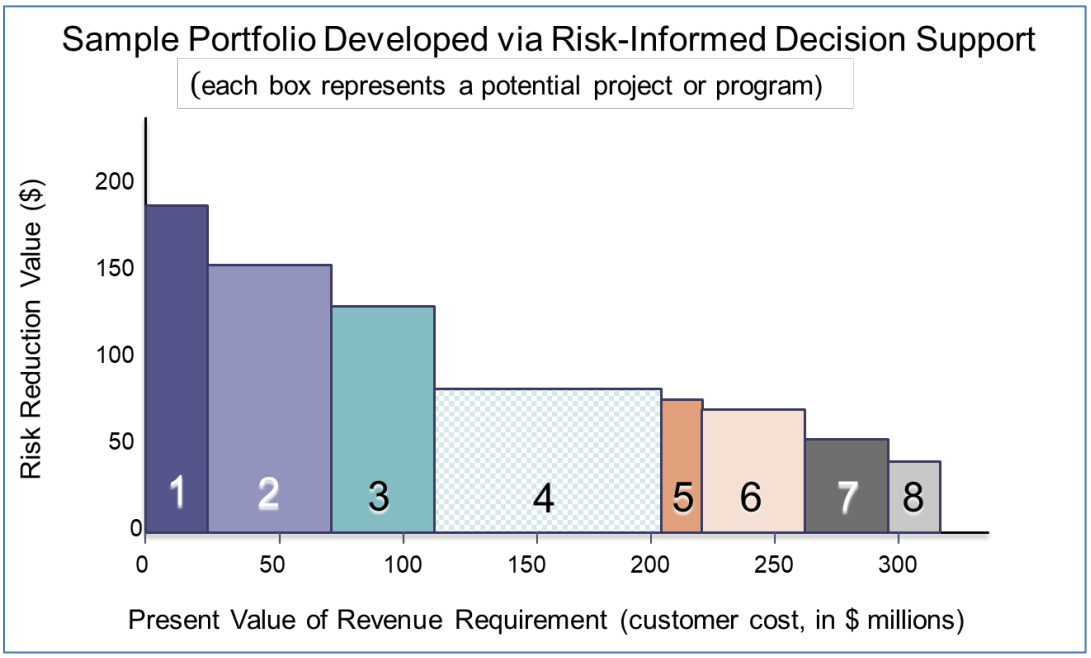
Value of Risk Reduction (in $)	=	Reduction in the Likelihood of an Adverse Event (in %)	✖	Consequence of the Adverse Event (in $)

Q. How do you recommend DTE determine the appropriate capital budgets and deployment speeds for various capital programs?

A. I recommend a systematic approach called risk-informed decision-making, or "RIDM" (also known as risk-informed decision support, or "RIDS"). It is ideal for optimizing a capital budget, and for selecting the projects that comprise it, when faced with constraints

[49] California PUC R20-07-013, Dec. 15, 2022, Decision 22-12-027, Appendix A.

(such as an interest in maintaining customer affordability). Using individual risk-informed benefit-cost analyses completed on a portfolio of potential projects as a starting point, the approach helps logically identify projects appropriate for deferral to future periods by making informed trade-offs. Ranking programs based on benefits (in dollars) relative to costs informs the trade-offs associated with various capital spending levels. A chart depicting the conceptual application of RIDS to a portfolio of potential projects is presented below.



The chart indicates that project 4 should be eliminated from further consideration, as costs exceed benefits. For the remaining projects, the size of the total capital budget informs the projects that should be deferred to a future period in an order that keeps the most beneficial projects and defers the least beneficial (as measured by benefits relative to costs). A total capital budget of $115 million looks like a good breakpoint, as it would retain projects 1, 2, and 3 in the budget. An extra $100 million would permit inclusion of

projects 5 and 6. An additional $100 million beyond that would include projects 7 and 8, and so on. With risk-informed decision-making, a utility and its regulator and stakeholders know the additional benefits they will get by increasing a capital budget, as well as the benefits that will be foregone by reducing a capital budget. These are the *informed trade-offs* mentioned above.

The point is that there are likely much better ways to develop capital budgets than the approach DTE is using, which appears to be almost entirely subjective with respect to the Company's strategic capital programs. As indicated earlier in this testimony (using PTMM as an example), the determination of how much capital should be devoted to various strategic capital programs – and therefore the number of circuits to be addressed and speed of deployment – appears to be based on subjective decisions made by senior management.[50] Also described earlier, senior management decisions about how much capital to invest, and how soon, are driven by capital bias. As a result, reliance on utility-proposed capital spending increases is not advised. Another DTE model, the Reliability Model, might be invoked in considering the optimum size of budgets for various strategic capital programs. This testimony turns to this subject next.

B. <u>The Reliability Model DTE uses to project system-wide improvements is unreliable.</u>

Q. Please summarize DTE's Reliability Model

A. DTE's Reliability Model projects system-wide improvements in average service interruption duration (SAIDI) and frequency (SAIFI) from various strategic capital

[50] Ex MEC-5, Company Supplemental Response to MNSCDE-8.5c(SI) together with attachments 2022, 2023, and 2024 Budget Appropriations; also Ex MEC-6, Company response to MNSCDE-8.16(d)(i).

programs. These programs include ETTP, 4.8kV Hardening, PTMM, 4.8kV circuit conversions, and Distribution Automation. DTE uses the Reliability Model's improvement projections to justify the size of its strategic capital program budgets. By implication, the Model's reliability improvement projects are also intended to justify most of the Company's request to extend and expand rider IRM.

Q. How does DTE's Reliability Model work?

A. The Reliability Model applies reliability improvements secured historically from these programs to circuits selected for these programs in the future. Characteristics specific to each circuit, including customer counts, overhead line miles, and historical reliability performance, are used to project reliability improvements for each circuit based on units (generally, line miles) of program to be completed.

Q. Why do you believe DTE's Reliability Model to be unreliable?

A. DTE's Reliability Model is an unreliable predictor of reliability improvements from strategic capital spending for at least four reasons:

- Circuits that had been recently tree trimmed were eliminated from the control groups used to determine historical program reliability improvement performance, inflating reliability improvement projections;
- Only one year's pre-program circuit reliability was used to establish baseline performance against which to compare post-program reliability improvements;
- Program "units completed" used by the Model to project reliability improvements are unlikely to be completed for the budgets provided, inflating reliability improvement projections;
- DTE refuses to place any of its profits at risk for failing to achieve the all-weather reliability improvements the Model projects.

Q. Please explain how the control group definitions DTE used to determine historical program performance inflate reliability improvements projected by the Model.

A. The Model attempts to use the historical reliability improvements demonstrated by various programs to project future reliability improvements from those programs. While this sounds eminently logical, it relies on accurate historical reliability improvement performance measurement. DTE's historical reliability improvement performance measures for various programs (with the exception of ETTP) are not accurate.

As explained earlier, multiple strategic capital programs require tree trimming as part of program implementation. Trees must be completely trimmed to complete PTMM work and 4.8kV hardening work, and to complete many types of 4.8kV conversion work. Even the installation of Distribution Automation devices requires a small amount of tree trimming, as does tie-line capacity expansion for Distribution Automation. This means it is extremely difficult to isolate the reliability improvements resulting from tree trimming from the reliability improvements resulting from strategic capital program work.

DTE did not attempt to isolate the impact of tree trimming from the impact of strategic capital program spending when determining historical reliability performance of the programs. In fact, DTE made matters worse by eliminating circuits that had been tree trimmed from the control group used to determine historical reliability performance.[51]

[51] See Company response to MNSCDE-8.1(i)(i) ("Explain, and provide a definition for, how circuits were selected for the 2018, 2019, 2020, and 2021 Control Groups. Provide a list of the circuits selected for each control group, and provide, for each" i. The substation and circuit identification; **Answer**: The control group consists of 4.8kV circuits that were never hardened and excludes those tree-trimmed in recent years. These circuits were selected as the control group for 4.8kV Hardening because they were typically designed and constructed during similar time periods with similar construction standards and are the same voltage class

DTE appears to have applied the "difference of differences" approach to determine the historical reliability improvements of various strategic capital programs. In this approach, a group of circuits to which a program was applied is used as a test group, and a group of circuits to which a program had not been applied is used as a control group. Reliability statistics are recorded for both groups pre- and post-program application. The change (difference) in reliability pre- to post-program in the test group is compared to the change (difference) in reliability in the control group over the same time periods to determine the improvement in reliability resulting from the program. The table below provides an example.

(All figures in minutes)	Average SAIDI Before Program	Average SAIDI After Program	Difference, Pre- to Post-Program
Test Group Circuits	100	90	10
Control Group Circuits	100	102	2
Difference of differences (improvement attributed from Program)			12

Circuits that have not had tree trimming will certainly perform much worse than circuits that have had tree trimming. Removing circuits that have had tree trimming creates an unfair control group for comparison. In fact, the proper control group for strategic capital programs that necessarily involve tree trimming is a control group consisting ONLY of circuits that received tree trimming at the same time, but no program spending. This would create an appropriate comparison, as both test and control group circuits had tree trimming, but only the test group had both tree trimming and a program applied. This

as circuits hardened. As circuits are hardened or tree trimmed, they are removed from the control group in subsequent years.").

would isolate the impact of the tree trimming from the impact of the program. As it stands, the reliability improvements the Model applies for programs that involve extensive tree trimming, including PTMM, 4.8kV hardening, and many if not most 4kV conversions are dramatically overstated, meaning that the program benefits the Model projects for future circuits are also dramatically overstated.

Q. Why would using only one year's pre-program reliability performance as a baseline for comparison to post-program reliability be a problem?

A. Weather variation is a big deal in reliability performance measurement. This is true even in cases where reliability data without major event days (generally, storms) is used to calculate reliability improvements, as DTE did when developing its Reliability Model. Consider a year in which a utility's service territory was subjected to an average number of major thunderstorms that were not classified as major event days. Let us assume that the average number of major thunderstorms not classified as major event days for our hypothetical utility is 10 storms. In the following year, assume the utility experiences 20 major thunderstorms that did not qualify as major event days. The reliability results of these two years, even with major event days excluded, will be very different.

Weather variation is the reason why Mr. Stephens and I always recommend using a minimum of three years' pre-deployment data as a baseline for quantifying reliability improvements from a program. (We also recommend using a minimum of three years' post-deployment data for the same reason.) DTE only employed one year of pre-

deployment reliability data to use as a baseline for calculating reliability improvements from strategic capital programs.[52]

Q. Please explain why "units completed" used by the Model to project reliability improvements are unlikely to be completed for the capital budgets DTE requests, and how this results in exaggerated reliability improvement projections.

A. The Model incorporates "units completed" by program to calculate reliability improvements.[53] As the number of units goes up, reliability improvements calculated by the Model increase, just as one would expect. However, this makes the Model sensitive to the counts of units completed. By comparing units completed over time in the Model to program budgets DTE proposes in its application over time, I calculated a cost per unit completed. Surprisingly, the cost per unit completed goes down over time for all five strategic capital programs, in some cases significantly. My calculations are presented in the table below.

	Cost per Unit Completed, 2024	Cost per Unit Completed, last year data is available[54]	Fall in cost per unit completed over time.
ETTP	$ 4,689	$ 3,902	17%
4.8kV Hardening	55,172	34,722	37%

[52] Direct Testimony of Allen J. Kryscynski at AJK-71:20.

[53] For most programs, "units" appear to represent circuit miles, but for Distribution Automation the "units" appear to be devices installed. See workpaper WP AJK U-21534 Reliability Model, tab "Program Inputs".

[54] For ETTP and 4.8kV Hardening programs, the last year data is available is 2025. Budgeted spending for these programs comes from Ex A-12 Sch B5.4, with ETTP from Steudel Direct, RCS-24, Table 7. For PTMM, 4.8kV Conversions, and Distribution Automation programs, the last year data is available is 2027. Budget data for these programs comes from Ex A-33 Sch X1 (IRM).

PTMM	8,416	7,547	10%
4.8kV Conversion	255,982	104,348	59%
Distribution Automation	9,265	7,200	22%

As costs typically go up over time, not down, particularly in these inflationary times, I am concerned that the number of "units completed" in the model are exaggerated relative to the number of units the Company will be able to complete for the capital budgets indicated. If the Company is unable to complete the count of units the Model assumes for the budgets indicate, the reliability benefits the Model projects will be unachievable, and the Model will again be exaggerating the reliability improvements projected. Given that DTE does not appear to employ any measurement standard for dollars per circuit mile completed or devices installed, discussed earlier in this testimony, my observation regarding variability in units completed is particularly concerning.

Q. Are there any other reasons to question the reliability improvements the Model projects?

A. Yes. DTE refuses to place any of its profits at risk for failure to achieve the reliability improvements its Model predicts.[55] While the Company cites weather variability as the reason, there are ways to address this concern. If the Company were truly confident in the improvements projected by its Reliability Model, it should be willing to place some of its profits at risk. As it stands, customers bear 100% of the risk that the value of reliability

[55] Ex MEC-7, Company response to MNSCDE-7.2(h).

improvements DTE delivers from its strategic capital programs will not be enough to cover the rate increases customers will have to pay for these programs.

VI. THE COMMISSION SHOULD REJECT DTE'S GRID AUTOMATION TELECOMMUNICATIONS PLAN AND DISALLOW COSTS INCURRED TO DATE

Q. Please provide a preview of this section of testimony.

A. This section of testimony supports my recommendation that the Commission reject DTE's Grid Automation Telecommunications plan and disallow costs incurred to date. It will summarize the plan, identify the presumptions DTE makes in justifying its plan, and explain the deficiencies in these assumptions.

Q. Please summarize DTE's Grid Automation Telecommunications Plan.

A. DTE's Grid Automation Telecommunications Plan consists of expanding the Company's fiber-optic data communications network (the largest part of the Plan's spending through 2025),[56] largely through connections to substations. The Company then plans to use that network as a base for a "last mile" wireless communications expansion,[57] which DTE plans for communications to smart meters, distribution automation and other field devices, distributed energy resources, autonomous (presumably electric) vehicles, and "mobile assets".[58] The Company's Plan will cost almost $107 million 2022-2028.[59]

[56] Direct Testimony of Shannen M Hartwick at SMH-22:17.

[57] Ibid, at SMH-26:20.

[58] Ibid, at SMH-25:7 and SMH-26:4.

[59] Ex. A-12 Sch B5.4, page 17, line 6 (for 2022-2025); Ex A-23 Sch M8 (2023 DGP), p. 137 of 274, Exhibit 10.1.3 (for 2026-2028).

Q. How does the Company communicate with substations and remote devices today?

A. Like all utilities of which I am aware, the Company communicates with substations and remote devices today through a variety of technologies, including fiber-optic cable and wireless technologies such as microwave, cellular, and radio (for smart meters). The Company owns the equipment that delivers some of these communications services, but also secures both fiber-optic and wireless communications services through third parties. As just one example, the Company owns fiber to about 25% of its substations, leases fiber serving about 1% of its substations, and communicates with the rest of its substations using both owned wireless equipment and leased wireless communication services.[60]

Q. What is the total cost of DTE's Grid Automation Telecommunications Plan?

A. The Company refused to provide details for the plan beyond 2025, citing that details for the Plan beyond 2025 are beyond the scope of the Company's application.[61] The Company's 2023 Distribution Grid Plan provides no additional information on the Telecommunications Plan.[62]

Q. What do you think of DTE's refusal to provide Plan information beyond 2025?

A. The fiber-optic cable installations proposed through 2025 are part and parcel of the Company's larger Plan. One cannot evaluate the appropriateness of the DTE proposal to

[60] Ex MEC-8, Company response to MNSCDE-7.4(a).

[61] Ex MEC-8, Company response to MNSCDE-7.4(b); *see also* Ex MEC-9, Company response to MNSCDE-7.3.

[62] See Ex A-23 Sch M8 (2023 DGP), pp. 140-42 of 274.

install fiber-optic cable through 2025 without an understanding of DTE's entire Plan, as the Telecommunications Plan appears to depend on the fiber-optic cable investments.

Q. What presumptions does DTE make in support of its Grid Automation Telecommunications Plan?

A. The Company makes two critical presumptions in support of its Plan. These include: 1) that many new technologies require real-time communications;[63] and 2) of all available options, Company-owned options provide the best combination of speed, control, security, and reliability.[64] The Company has not quantified the cost differences of the options,[65] and further, neither of the two presumptions are supported by data.

Q. Do the new technologies to which DTE refers require real-time communications?

A. No. The "new technologies" to which DTE refers include distribution automation, conservation voltage reduction, volt-VAR optimization, advanced metering infrastructure, demand response, and grid state monitoring (due in large part to distributed energy resources). All of these technologies and capabilities can perform at a very high level without real-time communications. In my experience wireless technologies that provide close to real-time data communications, from microwave to cellular, can deliver almost 100% of the benefit potential available from these capabilities and technologies, and DTE provides no evidence to the contrary.

[63] Direct Testimony of Shannen M Hartwick at SMH-22:17.

[64] *Id.*, from SMH-29:1 to SMH-42:17.

[65] *Id.* at SMG-40:4 (Figure 5); also Ex MEC-9, Company response to MNSCDE-7.3(d).

Q. Do Company-owned options provide the best combination of speed, control, security, reliability, and cost?

A. It is difficult to know for certain. There are likely some situations in which Company-owned options do provide the best combination of speed, control, security, reliability, and cost. However, in a large number of situations, and likely in a majority of situations, third-party solutions may offer the best combination of speed, control, security, reliability, and cost (to customers). Third-party solutions are more flexible, incurring fewer up-front costs and less risk for customers, than Company-owned solutions. Last but certainly not least, third-party solutions, as an operating expense, do not incur the Company cost of capital and income tax reimbursements that customers must pay on top of Company capital spending.

Q. Has the Commission asked DTE to analyze a variety of alternatives before advancing its Grid Automaton Telecommunications Plan further?

A. Yes. In DTE's last rate case, the Commission's Order agreed with the ALJ's recommendation on this issue, stating "[the ALJ] further found that the company should be required to provide an analysis of alternatives when requesting further extensions of the fiber network."[66]

Q. Has DTE completed such an analysis?

A. Not in my opinion. DTE Witness Hartwick provides a few pages of testimony describing a number of telecommunications alternatives, and a "Harvey Ball" type analysis comparing the relative pros and cons of each option on a scale of one to five, with one (unfavorable)

[66] Case No. U-21297, Dec. 1, 2023, Order, pp. 120-22.

represented by an open Harvey Ball, and five (favorable) represented by a closed Harvey Ball.[67] In my opinion, her analysis is not remotely adequate to support $107 million in spending, let alone the tens or hundreds of millions of dollars that might comprise the balance of the Telecommunications Plan (which DTE refused to provide).

Q. What would constitute an appropriate analysis?

A. Before making an investment of $100 million or more, an unregulated business would undertake a comprehensive "make vs. buy" study. Such a study would compare the pros and cons of each technology on technical, operational, cybersecurity, reliability, and other characteristics, and compare these pros and cons to the risks associated with each technology (generally, the size of the up-front investment) and the cost of each technology – not just initially, but over the lifetimes of each alternative's operation. An unregulated business might even employ outside experts to complete such a study to ensure objectivity. DTE has not completed such a study.[68]

Assessments of the characteristics of various alternatives should also be supported by data. For example, it would not be enough for DTE to claim that a public carrier's service is insufficiently reliable; DTE must identify the frequency with which commands issued over DTE's owned network failed compared to the frequency at which commands issued through the public carrier's network failed. Assuming the public carrier's performance was worse than the Company's (which should not be assumed), DTE should provide the consequence of the difference to customers. For example, of the increased

[67] Hartwick Direct at SMH-38.

[68] Ex MEC-9, Company response to MNSCDE 7.3(d).

failure rate observed (hypothetically) in commands issued over a public carrier network, how many resulted in service interruptions to customers, and what were the consequences to customers (in dollars) of these service interruptions? A precise quantification of Telecommunication Plan benefits in dollars is needed for comparison to the incremental costs of the Plan.

With an objective understanding of the pros and cons of each alternative relative to cost and risk, the next step would be to develop a tool to identify which alternative communications solutions are the most appropriate for application in certain situations and circumstances. The tool would use defined criteria, informed by the rigorous analyses described above, to help optimize communications technology choices for various situations' circumstances. DTE has not developed such a tool,[69] and clearly does not possess the data needed to inform the development of such a tool.

In short, DTE must provide evidence of data-driven decision-making of the sort described earlier in this testimony, and as described by Mr. Stephens in his testimony. If the Commission does not establish such expectations for the supporting analysis now, then DTE will continue to make unsupported proposals for telecommunications network capital spending in the future.

Q. What are your recommendations on the Company's Grid Automation Telecommunications spending and Plan?

[69] Ex MEC-8, Company response to MNSCDE-7.4(c).

A. I recommend that the Commission disallow Telecommunications Plan costs incurred in 2022 and remove Plan spending from the 2023-2024 bridge period and 2025 test year.[70] I make this recommendation based on three observations: 1) That DTE has not developed a benefit-cost or make vs. buy analysis that supports its spending or Plan; 2) That the Company has not complied with the Commission's Order to analyze alternatives to its Plan; and 3) That DTE refused to provide the Plan, of which the historical and proposed spending in its Application constitute a foundational part.

I further recommend that the Commission order the Company to solicit an independent expert to complete a comprehensive analysis of technical, operational, cybersecurity, and reliability pros and cons of various telecommunications options, and to compare these options to the risk and total lifecycle costs associated with each option. I further recommend that the Commission order the Company to complete a tool that appropriately identifies the best alternative to employ in various situations and circumstances.

VII. RECOMMENDATIONS AND CONCLUSION

Q. Please summarize your recommendations.

A, First, in Section II, I recommend that the Commission require DTE to slow the rate of capital spending, and require DTE to collect and provide more data on the effectiveness of the Company's vegetation management program relative to its proposed massive capital spending increases.

[70] These amounts are reflected in the workpapers and testimony of Mr. Stephens.

In Section III, I recommend the Commission constrain DTE capital spending and increase capital spending governance at DTE, and specifically that the Commission reject the Company's proposal to extend and expand rider IRM.

Section IV addresses the Company's vegetation management proposals. I discuss the Company's continued practice of inappropriately capitalizing vegetation management expenses through 4.8kV hardening, 4.8kV conversion, PTMM programs, and Distribution Automation, and I recommend that the Commission require DTE to identify costs, assess ratepayer impacts, and support the claimed propriety of this practice in its next rate case.

I further recommend that the Commission reject the Company's request to earn a return for shareholders on the Surge regulatory asset.

Next, I recommend the Commission require DTE to continue its annual tree trim report ordered in U-20162. Further, due to tree trimming's importance, and due to the upcoming completion of the Surge, I recommend the Commission order an audit of the state of the Company's overhead line right of way every five years, to commence in 2025 or 2026.

In Section V, I recommend the Commission disregard as unreliable two models the Company developed to justify its strategic capital spending increases - DTE's Global Prioritization Model and its Reliability Model.

Finally, in Section VI, I recommend the Commission reject the Company's Grid Automation Telecommunications proposal and disallow costs incurred on the program to date because the Company has not satisfied the Commission's U-21297 Order to "analyze"

various telecommunications technology options, and the Company has not adequately supported the options it has proposed in the instant application. I also recommend that the Commission order the Company to complete a make versus buy analysis comparing the pros and cons of various telecommunications technology alternatives, and a tool to identify the most appropriate alternative to select for various situations and circumstances.

Q. Does that complete your testimony?

A. Yes.

MS. ANDREWS: Thank you. Next, also on behalf of Attorney General Dana Nessel, Michigan Environmental Council, and the Natural Resources Defense Council, I'd move to bind into the record the Direct Testimony of Dennis Stephens, which consists of a cover page, table of contents, 47 pages of questions and answers, and for the admission of Exhibits MEC-10 through MEC-22, and I would note that there is a public and confidential version of his testimony, and I'd move for the admission of both into the respective transcripts -- or I'm sorry -- to bind both into their respective transcripts.

JUDGE WALLACE: Got it. All right. Is there any objection to binding in the public and confidential direct testimony of Mr. Stephens?

Hearing none, the testimony is bound in.

Is there any objection to the admission of Exhibits MEC-10 through MEC-22?

Hearing none, those exhibits are admitted.

(Public Direct Testimony bound in.)

(Confidential Direct Testimony found on Page 5263 of the Confidential Record.)

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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 of electric energy, and for miscellaneous accounting authority.	U-21534

PUBLIC VERSION

DIRECT TESTIMONY OF DENNIS STEPHENS

ON BEHALF OF

ATTORNEY GENERAL DANA NESSEL,
MICHIGAN ENVIRONMENTAL COUNCIL, AND
NATURAL RESOURCES DEFENSE COUNCIL

July 26, 2024

DIRECT TESTIMONY OF DENNIS STEPHENS FOR AG-MN
CASE NO. U-21534

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DIRECT TESTIMONY OF DENNIS STEPHENS FOR AG-MN
CASE NO. U-21534

I. INTRODUCTION, QUALIFICATIONS, PREVIEW AND PERSPECTIVE

Q. Please state for the record your name, position, and business address.

A. My name is Dennis Stephens. I am an independent consultant specializing in electric and gas distribution operations, planning, technologies, asset management, and performance measurement. I frequently support the Wired Group in its work with clients. My business address is DS Consulting, 1153 Bergen Pkwy, Suite 130, Evergreen, CO 80439.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of the Michigan Attorney General (AG), Michigan Environmental Council (MEC), and Natural Resources Defense Council (NRDC), collectively referred to as "AG-MN".

Q. Please summarize your experience in the field of utility regulation.

A. After graduating from the University of Missouri with a bachelor's degree in Electrical Engineering, I began work for Xcel Energy (then Public Service Company of Colorado) in 1976 as an electrical engineer in distribution operations. In a series of electrical engineering and management roles of increasing responsibility, I gained experience in distribution planning, operations, and asset management, as well as the innovative use of technology to assist with these functions. Positions I've held over the years have included Director, Electric and Gas Operations for the City and County of Denver Colorado; Director, Asset Management; and Director, Innovation and Smart Grid Investments, for all of Xcel Energy.

In 2007, I was asked to lead parts of Xcel Energy's SmartGridCity™ demonstration project in Boulder, Colorado, the first of its kind at the time, covering 46,000 customers. I developed the technical foundations for the project, including the development of all

concepts presented to the Xcel Energy Executive Committee for project approval, and including the negotiations with technology vendors on their contributions to the project. As Director of Utility Innovations for Xcel Energy, I also worked with many software providers, including ABB, IBM, and Siemens, helping them develop their distribution automation ideas into practical software applications of value to grid owner/operators. I retired from Xcel Energy in 2011, and now work for the Wired Group on a part-time basis.

In the roles noted above, I was directly responsible for distribution grid reliability and service restoration, and indirectly responsible for grid reliability and service restoration in all of these roles. This is highly relevant in proceedings such as this one, in which grid reliability and resilience are significant considerations. For a good portion of my career at Public Service Company of Colorado, capital spending was constrained. My experience maintaining strong distribution grid reliability and resilience performance in the face of capital constraints is highly relevant to this testimony. My curricula vitae is attached as Ex MEC-10.

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

A. I filed testimony in DTE's most recent rate case.[1] I am also known to the Michigan Public Service Commission (Commission) and Staff from other proceedings. Working with my Wired Group associate Paul Alvarez, we helped the Association of Businesses Advocating for Tariff Equity (ABATE) develop several sets of Commentary, which ABATE filed in recent years. In U-20147, we helped ABATE develop Comments regarding (1) The development of five-year distribution plans in Michigan generally (September 11 and

[1] Case No. U-21297, Direct Testimony of Dennis Stephens, 6 TR 3359 *et seq.*

November 18, 2019); (2) Five-year distribution plans and storm performance (October 1, 2021); (3) Consumers Energy's Distribution Infrastructure Investment Plan (June 23, 2021); and (4) DTE Electric Company's Distribution Grid Plan (September 29, 2021). We also helped ABATE develop Comments in U-21122, the August 2021 2021 storm reliability performance and distribution planning docket (September 24, 2021). Mr. Alvarez and I also gave a presentation on distribution planning and utility proposal cost-effectiveness testing, to include risk-informed benefit-cost analysis and risk-informed investment decision support, in a Staff-led workshop on distribution plan development held August 14, 2019.

In addition, I have testified on behalf of consumer, business, and environmental advocates in proceedings related to electric distribution utility planning, investment, performance, and regulation before 10 other state utility regulators in the past 10 years, including California, Georgia, Illinois, Indiana, Maryland, Massachusetts, North Carolina, Oklahoma, Virginia, and Washington. A complete list of proceedings in which I've submitted testimony to state utility regulators, with proceeding numbers and dates, can be found at Exhibit MEC-10.

Q. What is the purpose of your testimony?

A. I am testifying on behalf of AG-MN regarding the distribution capital spending proposed by DTE Electric Company ("DTE" or "Company") in the instant proceeding, described as strategic capital programs in the Company's 2023 Distribution Grid Plan ("DGP").[2] Cost

[2] Ex A-23 Sch M8 (hereinafter "DTE 2023 DGP").

recovery for many of these programs is proposed through the infrastructure recovery mechanism rider, or "IRM", the Company proposes to extend and expand.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit MEC-10:	Curricula Vitae of Dennis Stephens
Exhibit MEC-11:	Strategic Capital Disallowance Table
Exhibit MEC-12:	DS Equp Fail Analysis (from Case No. U-21297, Company Supplemental Response to MNSCDE-2.3 outages w Field Notes.xlsx)
Exhibit MEC-13:	Case No. U-21297 AGDE-4.103b + Attachment *U-21297 AGDDE-4.103b-01 PTMM and 4.8kV Hardening Metrics*
Exhibit MEC-14:	Company Responses to MNSCDE-3.8(c) and 8.9(c)
Exhibit MEC-15:	Company Responses to MNSCDE-3.15(c)(i), (ii), 3.23(d), 3.1(a), (b), (c), and excerpt from Attachment *U-21534 MNSCDE-3.1-01 Outages 2017-2023 (Dec. 2023 outages)*
Exhibit MEC-16:	Company responses to MNSCDE-3.26(a), (b) with Attachment *U-21534 MNSCDE-3.26-01 Subtransmission Interruptions*
Exhibit MEC-17:	Company Response to MNSCDE-1.8(a) + Attachment *NDA CEII U-21534 MNSCDE-1.8a DTEE GPM / GPM Results Tab / Col A to AB ("blue")*
Exhibit MEC-18:	Company Responses to MNSCDE-5.4(a), (b), (c)
Exhibit MEC-19:	Company Response to MNSCDE-8.5(a) with Attachment *U-21534 MNSDCE-8.5a-01 Project Alternatives*
Exhibit MEC-20:	Attachment MNSCDE-8.5(c) (S1) *-04 4.8kV CC Almond Relief and Circuit Conversion (Midas)*

Exhibit MEC-21:	*U-21534 MNSCDE-8.5c(S1)-47 Substation Redesign & Rebuilt Tie 4105 Phase 1, U-21534 MNSCDE-8.5c(S1)-48 Substation Redesign & Rebuilt Tie 4105 Phase 3, U-21534 MNSCDE-8.5c(S1)-49 Substation Redesign & Rebuilt Tie 4105 Phase 3*
Exhibit MEC-22:	Company Responses to MNSCDE-8.18(d)

Q. Please provide a preview of your testimony and recommendations.

A. This testimony examines multiple strategic capital programs described in the Company's 2023 DGP and associated requests for cost recovery. While I will examine the Company's strategic capital programs from technical and financial perspectives, my Wired Group colleague Mr. Paul Alvarez, also testifying on behalf of AG-MN, examines the Company's proposals and some of the models used to justify them, from policy and regulatory perspectives. Our two testimonies are best considered together as his testimony provides valuable context and perspective for my evaluations and recommendations.

My testimony is organized in the order presented in the table below, which also summarizes my recommendations for each item.

Spending Category	Summary of recommendations
4.8 kV Hardening Program	1. Switch program to DLPD wire removal only. 2. Reject $73.3 million in excess 2024 spending. 3. Reduce test year spending to $43.2 million (disallowing $81.8 million) to accommodate switch to DPLD.
4.8kV Conversion Program (incl. Detroit and Pontiac)	1. Require DTE to provide support for its preferred pace of voltage conversions, including assessment of rate impact and value of benefits of Conversions to ratepayers.

	2. Require DTE to support large Conversion projects ($10 million or more) before proceeding with the project. 3. Reject Conversion spend in 2026 and 2027 IRM.
Pole and Pole Top Maintenance & Modernization Program	1. Require DTE to assess reliability difference between PTM and PTMM circuits using historical data to prevent conflating tree trim benefits and to calculate the value of reliability improvements relative to the costs of new pole top construction and inspection standards. 2. Reduce test year spending by $57.6 million to maintain spending at level approved in U-21297 for 2024 ($63.45 million). 3. Reject PTMM spend in 2026 and 2027 IRM.
Subtransmission Redesign & Rebuild Program	1. Reject approval for any new projects in this discretionary program until DTE presents an appropriate evaluation framework indicating value to customers in excess of project costs. 2. Require DTE to support large Substation R&R projects ($10 million or more) before proceeding with the project. 3. For 3 projects DTE will place into service in 2024 and 2025, disallow $28.14 million. 4. Reject Subtransmission redesign and rebuild spend in 2026 and 2027 IRM.
Distribution Automation Program	1. Require DTE to support future projects with circuit-specific benefit-cost analyses. 2. Reduce test year spending by $101.2 million to maintain spend level approved in U-21297 for 2024 ($24.5 million). 3. Reject Distribution Automation spend in 2026 and 2027 IRM.
Strategic and Service Drop OH-UG Pilots	1. Discontinue pilot (program). 2. Reject 2024 ($15.6 million) and test year ($16.02 million) spending
Breaker & URD Replacement	Reject proposed spend in 2026 and 2027 IRM.

Q. Please provide relevant context for your testimony.

A. It is no accident that all of the spending categories I have examined constitute distribution capital spending that is discretionary. I define discretionary spending as "If the capital is

not spent, can customers still have safe and reliable service?"[3] If the answer is no, then the spending is non-discretionary (mandatory). If the answer is yes, then the spending is discretionary and a risk-informed benefit-cost analysis should be performed to quantify whether the dollar value of the risk reduction to customers exceeds project costs to customers.

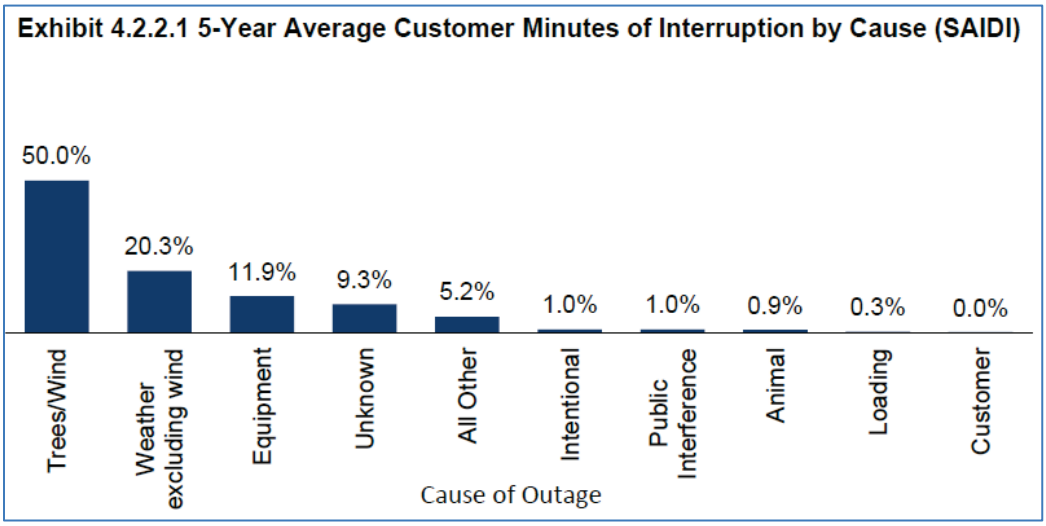
An example illustrates the difference between mandatory and discretionary spending. An overhead distribution line damaged by a storm must be repaired immediately. Such spending is clearly mandatory, and no benefit-cost analysis is needed. A decision to rebuild an entire distribution line on the basis of a subjective assessment of the line's condition is discretionary. Discretionary investments offer a great degree of optionality as to whether to complete a project at all, and if so, when and how. These decisions should be informed through a risk-informed benefit cost analysis (as described by Mr. Alvarez).

The Commission should consider this perspective because what DTE presents in the instant application, and in its last rate case (U-21297), and in its 2023 Distribution Grid Plan, appears to be that reliability improvements will be limited without massive increases in capital spending. I wholeheartedly disagree with this apparent DTE perspective for at least three reasons.

First, storm response and vegetation management – not equipment condition – have driven the Company's historically poor (relative to peers) reliability performance. The

[3] Compliance with a recognized authority's standard or specification, as strictly interpreted, can also constitute a required investment.

Company's own data indicates that while vegetation contact, wind, and weather are responsible for 70.3% of system average service interruption duration (SAIDI), the percentage of SAIDI caused by cause "equipment" is just 11.9%:[4]



However, I note that even this percentage likely exaggerates the need to replace "aging" equipment. In my examination of field notes the Company recorded on a random sample of 100 service interruptions classified as "equipment" related, only 12% of service interruptions had field notes sufficient to determine root cause. Of these 12%, 67% could be traced to unprompted failures of equipment in service, while 33% were caused by vegetation contact or damage by third parties.[5]

Second, the reliability improvement estimates DTE calculates for many of its programs are dramatically exaggerated. As described in Mr. Alvarez's testimony, the

[4] 2023 DGP, Ex A-23 Sch M8 Exhibit 4.2.2.1, p. 41 of 274.

[5] Exhibit MEC-12, DS Equp Fail Analysis (from Case No. U-21297, Company Supplemental Response to MNSCDE-2.3 outages w Field Notes.xlsx).

Company appropriately employs a "difference of differences" approach to quantifying reliability improvements from various capital programs using "test" and "control" groups of circuits. But the Company's control group definition dramatically exaggerates reliability improvements from capital programs by eliminating circuits that have had tree trimming. This is directly opposite of the correct way to isolate the performance improvements from tree trimming to the performance improvements of capital programs that include tree trimming,[6] as illustrated in the hypothetical table below.

(All figures in minutes)	Average SAIDI Before Program	Average SAIDI After Program	Difference, Pre- to Post-Program
Test Group: Tree-trimmed circuits with 4.8 kV hardening	100	60	40
Control Group: Tree-trimmed circuits without 4.8 hardening	100	63	37
Difference of differences (improvement from 4.8kV Hardening)			3

Third, DTE's system-wide reliability performance has been completely unresponsive to massive increases in the Company's capital spending in recent years, as shown in the chart presented in Mr. Alvarez' testimony.[7] DTE has presented zero historical evidence that it's capital spending has improved system-wide reliability in the past,

[6] Capital programs that include full or extensive tree trimming include 4.8kV Hardening, PTMM, and 4.8kV Circuit Conversions.

[7] See DTE SAIDI & Distribution Plant Additions (with Major Event Days vs. US IOUs).

meaning that the Commission should be deeply skeptical of DTE's claims that capital spending will improve reliability in the future.

II. THE 4.8kV HARDENING PROGRAM

Q. Please summarize DTE's 4.8kV Hardening program.

A. DTE's 4.8kV Hardening program is supported in part as a safety program, as it reduces the frequency of wire-down events. It does this by removing overhead wire no longer used by the Detroit Public Lighting Department ("DLPD") from the Company's utility poles. When this unused wire, which is no longer being maintained, falls to the ground, it can come into contact with energized DTE wires, inadvertently energizing the downed DLPD wire – a dangerous condition to be sure. Once the DLPD wire has been removed, there is obviously no risk that an energized DLPD wire can fall to the ground. Citing this safety benefit, the Commission approved the 4.8kV Hardening program at a level requested by DTE in its last rate case.[8]

Q. Does the 4.8kV Hardening program eliminate the risk of energized wire down events?

A. No, it does not. Coincidentally, DTE's 4.8kV circuits in Detroit were designed without a neutral wire. The lack of a neutral wire can make it difficult for circuit breakers, reclosers, fuses, and other protective devices to recognize the fault that occurs when an energized DTE conductor falls to the ground. Failure to recognize a fault means protective devices on these 4.8kV circuits are more likely to remain closed in the event of ground contact, with the result that power continues to be delivered to a downed line. Thus, while the

[8] Case No. U-21297, Dec. 1, 2023, Order, p. 93.

removal of DPLD wire, which is no longer used and is thus less likely to be maintained, eliminates the risk that an energized *DPLD* wire will fall to the ground, it does NOT eliminate the risk that an energized *DTE* conductor will fall to the ground and not be deenergized, given that the hardening program does not eliminate the fact that there is no neutral wire on the 4.8kV system. In its requests for approval of large amounts of funding for the 4.8kV Hardening program in prior cases, DTE may have created an exaggerated impression of the safety benefits of the 4.8kV Hardening program. It does not appear that DTE discouraged any exaggerated impression of safety benefit in the Technical Conference workshop DTE hosted on March 22, 2023.[9]

Q. Are there alternatives to the 4.8kV Hardening program that provide comparable safety benefits?

A. Yes. Removing the DPLD wire alone will provide almost all of the safety benefits of the 4.8kV Hardening program at greatly reduced cost, and with a greater deployment speed.[10] The marginal added safety benefits of the 4.8kV Hardening program over the option to simply remove the DPLD wire are due to two extra steps the 4.8kV Hardening program takes over the "remove DPLD Only" option to reduce the risk that DTE conductor will fall to the ground. These include 1) full tree trimming (vs. the "as needed" tree trimming associated with the DPLD wire removal only option); and 2) replacement of all crossarms (vs. the "as needed" crossarm replacement associated with the DPLD wire removal only

[9] Ex A-23 Sch M12.

[10] Ex A-23 Sch M12 (DTE Technical Conference presentation March 22, 2023)., slides 31 ("ARC Wire Removal Only") and 32 ("4.8kV Hardening").

option).[11] But these additional steps are part of other initiatives. Full tree trimming will occur on the Company's newly-achieved five-year tree trimming cycle without 4.8kV Hardening.[12] Replacing crossarms where there is no documented "need" provides almost no incremental reduction in downed conductor risk, and replacing crossarms when defects are identified is part of the pole top maintenance program in any event. Moreover, the Company's new pole top construction standards, discussed below, further increase the cost of replacing crossarms under the 4.8kV Hardening program.

Q. How much less costly is the "remove DLPD wire only" option than the 4kV Hardening option?

A. In the Technical Conference DTE hosted in March of 2023, the Company indicated the cost of the DLPD removal option is $175,000 to $207,000 per mile, while the 4.8kV Hardening option costs $333,000 to $375,000 per mile.[13] Using averages, the DLPD removal option is 46% less costly than the 4.8kV Hardening option on a per mile basis.

Q. Does the 4.8kV Hardening program provide reliability improvements that the removal of DPLD wire alone does not provide?

A. DTE claims that the reliability improvements of the 4.8kV Hardening program are approximately double the reliability improvements available from the removal of DPLD wire alone.[14] Almost 100% of this difference is attributable to the full tree trimming that

[11] *Id.*

[12] Direct Testimony of Rachel C. Steudle at RSC-15.

[13] Ex A-23 Sch M12 slides 31 and 32; see also Elliot Andahazy Revised Direct at MEA-18 Table 2 (average cost per mile for Arc Wire Removal is $191,000 and for 4.8kV Hardening is $353,000).

[14] Ex A-23 Sch M12 slides 31 and 32.

occurs (and is inappropriately capitalized) through the 4.8kV Hardening program that does not occur under the DPLD wire removal only option. DTE is required to complete the tree trimming in any event, meaning that the reliability benefits from tree trimming should not be credited to the 4.8kV Hardening program. (It also means that tree trimming under the 4.8kV Hardening program should not be capitalized, as Mr. Alvarez recommends.) Almost none of the difference in reliability is reasonably attributable to replacing wood crossarms that do not indicate a need for replacement (as DTE's 4.8kV Hardening program does). Also, as indicated earlier, the errant control group definitions DTE used to determine the reliability improvements from strategic capital spending programs dramatically exaggerate DTE's reliability improvement claims and cannot be relied upon.

Q. Why would DTE recommend a 4.8kV Hardening program over the "DPLD wire removal only" option when the latter provides comparable safety improvement at almost half the cost and faster deployment speed?

A. It may be because the 4.8kV Hardening program grows DTE's rate base at almost twice the cost per mile as the DPLD wire removal only option. What is needed is a risk-informed benefit-cost analysis showing that the dollar value of the incremental reliability and safety benefits of the 4.8kV Hardening program over the DPLD wire removal only option exceeds the incremental cost of the 4.8kV Hardening program. DTE has not completed such an analysis.[15] Mr. Alvarez explains the approach to risk-informed benefit-cost analyses the California PUC has ordered its utilities to complete for spending intended to deliver reliability and safety benefits. I recommend such an approach be used to complete a

[15] See Company response to MNSCDE-8.2(c).

benefit-cost analysis before the Commission determines that the 4.8kV Hardening program provides greater safety and reliability benefits per dollar than the option of removing the DPLD wire only.

Q. Are there other reasons why the Commission should order DTE to switch from the 4.8kV Hardening program to the "remove DPLD wire only" program?

A. There is at least one additional reason: most of the work completed under the 4.8kV Hardening program (other than full tree trimming, which must be completed irrespective of hardening) will be rendered redundant when a 4.8kV circuit that has been hardened is converted to a 13.2kV circuit. DTE cannot justify the installation of fiberglass crossarms with a service life likely in excess of 50 years on a circuit DTE aims to convert to 13.2kV in the next 15 years or so.[16]

Q. In addition to illustrating excess, unsupported discretionary capital spending, do you have other observations about the Hardening program?

A. Mr. Alvarez describes how the use of rider recovery (and forward test years) introduces moral hazard in capital budget development, encouraging utilities like DTE to propose more in a spending plan than a utility would risk spending under traditional ratemaking. DTE's 4.8kV Hardening program is evidence of this phenomenon. Information asymmetry also adversely impacts challenges to utility spending proposals.

Q. What are your recommendations regarding DTE's 4.8kV Hardening program?

[16] 2023 DGP, Ex A-23 Sch M8, pp. 120-21 of 274.

A. I recommend the Commission order the Company to eliminate the 4.8kV Hardening program immediately in favor of the "remove DLPD wire only" option. I also recommend the Commission reduce test year spending to the amount required to complete the same number of miles of DLPD wire removal that it would have hardened with the $80 million requested for 2024. As DLPD wire removal costs 46% less than 4.8kV Hardening per circuit mile, I recommend the Commission reduce the Company's test year capital spending for DLPD wire removal program to $43.2 million to reflect shift from Hardening to DLPD wire removal only.[17] I further recommend the Commission disallow $73.333 million from the bridge period (2024) as a result of DTE's excess spending above what it requested and above what the Commission approved in U-21297, and for the additional reason that DTE has consistently failed to evaluate and support the efficacy of Hardening – independent of tree trimming. Finally, I also recommend the Commission require DTE to establish and present in its next rate case metrics, such as dollars per circuit mile of DPLD wire removed, to budget and monitor DPLD wire removal costs.

III. 4.8KV CIRCUIT CONVERSION PROGRAM

Q. Please summarize the Company's 4.8kV Circuit Conversion Program.

A. DTE has 16,720 miles of overhead 4.8kV and 8.3kV line miles (and 2,372 miles of underground 4.8kV and 8.3kV lines), or 40% of total distribution miles.[18] The Company

[17] The Company proposed increasing Hardening from $80 million it proposed for 2024 to $125 million for the test year. My recommendation rejects that increase and reduces the $80 million by 46% to reflect DPLD program cost savings as discussed above.

[18] 2023 DGP, Ex A-23 Sch M8, Exhibit 9.3.1.2, p. 109 of 274.

aspires to convert all circuits not already operating at 13.2kV to 13.2kV operations by about 2040, or within about 15 years.[19] The Company estimates the cost to complete the conversion will be as much as $25 billion in today's dollars,[20] or over $11,000 for every one of DTE's 2.25 million customers.[21]

Q. Please summarize the Company's spending plan for 4.8kV circuit conversion.

A. DTE is proposing to substantially ramp up and increase conversion spending over the next 15 years. According to the 2023 DGP, DTE proposes to maintain spending in the bridge and test years at a relatively low level, then increase spending in the IRM years, then really increase spending for 2029 and beyond:[22]

9.3.5 4.8kV Conversion Plan for 2024-2028

Exhibit 9.3.5.1 Projected 4.8kV Conversion Capital Investment

Project/Program ($ millions)	2024	2025	2026	2027	2028	Total Investment 2024-2028
CODI	$95	$126	$148	$119	$90	$579
4.8kV Conversions	$66	$66	$185	$243	$310	$869
4.8kV ISO down Area Conversions	$10	$10	$10	$10	$10	$50

[19] *Id.* at 120-21 ("the Company has developed an aspirational goal to convert all the lower voltage (4.8kV and 8.3kV) circuits and substations by 2040.").

[20] *Id.* at 120.

[21] This cost estimate may be low; the average cost per mile converted noted in the 2023 Technical Conference ($2.7 million) multiplied by 16,720 miles is over $45 billion. *See* Ex A-23 Sch M12 slide 34.

[22] 2023 DGP, Ex A-23 Sch M8, Exhibit 9.3.4, p. 120 of 274.

DTE identified the following spending plan for its 4.8kV conversion program in the instant proceeding:[23]

	2022	2023	2024	2025	2026	2027
Rate Case	104.483	161.932	199,154	78.755		
IRM			1,608	185,812	190,000	240,000

In U-21297, the Commission reduced DTE's 2024 test year proposed spending ($370.141 million) by the amount recommended by Staff ($115.9 million), thus approving $254.241 million in this program for the test year.[24] The Commission also approved in U-21297 DTE's proposed 2024 and 2025 IRM spending, subject to the IRM conditions.[25] The spending at issue in this proceeding is the $78.8 million in the test year and the proposed 2026 and 2027 IRM expansions and increases.

Q. Do you have concerns about DTE's plans for 4.8kV conversions?

A. I do. Before proceeding to implement these conversions, DTE must answer key questions. Why convert all these circuits in 15 years? What will be the rate impacts of such a pace? What are the alternatives to circuit conversion? What are the risks of not converting all these circuits in 15 years? What are the consequences of those risks? What is the value to DTE customers for its planned investments? Given the cost and scale of the 4.8kV conversion effort, DTE must justify its preferred conversion timeframe. DTE must substantiate the program – including the pace of it. As DTE likely built these circuits over a 50-year period from 1900 to 1950, rebuilding all these circuits in 15 years is an

[23] Ex A-12 Sch B5.4 p. 16 line 115; Ex A-33 Sch X1 (IRM).

[24] Case No. U-21297, Dec. 1, 2023, Order, pp. 108-113

[25] Case No. U-21297, Dec. 1, 2023, Order, pp. 290-91.

unreasonable aspiration. Moreover, DTE has not produced a benefit-cost analysis for planned conversions. DTE should pause its proposed ramp-up and demonstrate both that its planned pace of conversions – given the cost and value to ratepayers – is justifiable.

Q. What justifications does DTE provide for its goal of converting all circuits to 13.2kV in 15 years?

A. DTE's 2023 DGP cites three primary reasons for converting 4.8kV circuits to 13.2kV:[26] 1) Safety, because the design the Company followed when building the circuits results in an increased risk that a downed wire will remain energized; 2) Reliability, because the Company claims that 4.8kV circuits are less reliable than 13.2kV circuits; and 3) Capacity, because 13.2kV circuits can carry three times the load of 4.8kV circuits (to accommodate electric vehicles, for example).

Q. Is reliability a reasonable justification for converting all the Company's circuits to 13.2kV?

A. Reliability improvement is not a reasonable justification because data the Company provided in discovery in U-21297 shows the reliability of 13.2kV circuits (as measured by system average interruption duration without major event days) was worse during 2018-2022 (124 minutes) than the reliability of 4.8kV circuits over the same time period (97 minutes).[27] DTE would have to show on a project-level basis reliability benefits resulting from voltage conversion.

[26] 2023 DGP, Ex A-23 Sch M8, pp. 108-109 of 274.

[27] Using data provided by DTE in Case No. U-21297, U-21297 MNSCDE 2.2-01 Non-AC Network Circuits.xlsx.

Q. What is your perspective on the safety justification for converting 4.8kV circuits?

A. As described in the section on DTE's 4.8kV Hardening program, the design of the Company's 4.8kV circuits likely increases the risk that a downed conductor will remain energized if it falls to the ground. However, this is a design condition that has existed on the Company's 4.8kV circuits since they were constructed, likely between 75 and 120 years ago. This begs the question why all 4.8kV circuit conversions should be completed in the next 15 years.

Q. What is your perspective on the capacity justification for converting 4.8kV circuits?

A. Regarding capacity, of the Company's 1,945 4.8kV circuits, the peak loads on just 111 (5.7%) of these exceeded their day-to-day equipment ratings as of 2022.[28] Circuits with peak loads above or near equipment ratings should be prioritized for conversion first. There are reasons why peak loads may grow, namely, electric vehicles ("EV"). The Company predicted that about 55% of customers will be served by overloaded substations under its high EV adoption scenario.[29] However, DTE indicates capacity expansion may drive 4.8kV conversions beyond 2029, but nearer-term conversions are prioritized based on firm rating and overloads, as well as wire downs and risk ranking.[30] Moreover, DTE recognizes that EV adoption will likely concentrate in geographic "clusters" (neighborhoods) within a subsection of a circuit.[31] DTE should sync its pace of converting 4.8kV circuits conversions with evidence related to increasing electrification, evaluated in

[28] Ibid.

[29] 2023 DGP, Ex A-23 Sch M8, pp. 25-26.

[30] *Id.* at pp. 119-21.

[31] *Id.* at p. 25.

the context of available and emergent opportunities to mitigate load impacts, but it has not done so in this case nor the 2023 DGP. Its goal of converting all 4.8kV circuits to 13.2kV in 15 years is not justified on the basis of growing capacity.

Q. Has DTE provided any cost-benefit analysis supporting its conversions program?

A. No. DTE produced a benefit-cost analysis for the PTMM and undergrounding program, but not for the conversions program. DTE's Global Prioritization Model (GPM) prioritizes conversion projects but does not evaluate their likelihood of risk, total costs, and projected benefits and avoided costs, as discussed by Mr. Alvarez. It is also notable that DTE has now undertaken and completed multiple conversion projects in the City of Detroit and elsewhere.[32] As a result, DTE should have ample data to demonstrate the benefits achieved and total actual costs of conversion projects.

Q. Do you have any concerns about DTE's request for approval of proposed conversion projects?

A. Yes, it lacks transparency. First, it is important to note the scale of voltage conversion projects. Most are multi-million-dollar projects that span many years.[33] The Company plans and receives corporate approval for conversion projects over $10 million early in the project planning, though regulatory approval for the project may not be received until the project is in service. In U-21297, the ALJ noted that "almost all of the CODI [conversion] projects have in-service dates beyond the test year" and that DTE's application, including

[32] Ex A-12 Sch B5.4, p. 14 rows 28 to 36 to p. 15 row 56 (conversion projects in service 2023, 2024, or 2025).

[33] See Ex A-12 Sch B5.4 pp. 14-16.

Exhibit A-23 Schedule M5, "fail to present the total cost for any of the projects scheduled from 2025 to 2030."[34] Similarly for non-CODI conversions, "the ALJ found that most of these projects have in-service dates beyond the test year and the company is not seeking any revenue related to them in the instant proceeding."[35] DTE similarly acknowledged that conversion projects "that will not be in service during the test year have no impact on the revenue requirement."[36] Even so, the Commission rejected the ALJ recommendation to not include conversion project costs in rate base and instead found their post-test-year in-service date is not a basis to preclude the work from being included in rate base.[37] This begs the question: at what point must DTE support the reasonableness and prudence of these costly, multi-year projects to obtain regulatory review and approval? The Commission should provide clarity.

Q. Can you provide an example of your concerns about approval transparency?

A. Yes. Take 4.8kV CC: Almont Relief Circuit Conversion (Midas) as an example.[38] This conversion project has an in-service year of 2025.[39] DTE anticipates spending $1.0 million in the test year. The "*estimated* project cost" was $30,730,922, though DTE provided "estimated" annual spending for only about $11 million of this project.[40] DTE provided no

[34] Case No. U-21297, Dec. 1, 2023, Order, p. 109 (citing PFD, p. 285).

[35] *Id.* at 112 (citing PDF at 290).

[36] *Id.* at 110 (referring to DTE exceptions).

[37] *Id.* at 111, 113.

[38] Ex A-12 Sch B5.4, p. 15, line 41.

[39] *Id.*; see also Ex A-12 Sch B5.4, p. 23 line 102 (in-service assumption for Midas is December 2025.

[40] Ex A-23 Sch M6, p. 10.

assessment of alternatives nor itemized costs for this project in its supporting exhibit.[41] DTE did not identify the actual total capital spend on this project to date, nor an updated estimated of the total project cost. However, in discovery, DTE produced the Company's management approval for this project; because it is an individual project greater than $10 million, it requires specific management approval.[42] The approval shows the Company estimated the project to cost customers $36.2 million over 15 years:[43]

DTE Energy

Appropriation Request

Summary Sheet

Project Name:	Midas Subs - Below grade, Conduit Midas Subs - Above grade, OH, Cable	Capital Budget / Project #:	I-000404-0027 (MEP) I-000801-0001 (DO)
Utility/Non-Utility:	Utility	Project Type:	Distribution
Business Segment:	Electric Utility	Business unit within budget?:	Yes
Business Unit:	MEP / DO	Project Start Date:	Mar-2019
Project Sponsor:	Joi Harris / Sharon Pfeuffer	In-Service Date:	2022, 2023
		Post Investment Evaluation Date:	2025

Current Approval Request ($Millions):	$28.9
Previous Request(s) ($Millions):	$1.4
Total Project ($Millions):	$30.3

Financial Summary ($Millions)

	2020 & Prior Years	2021	2022	2023	2024	2025	Beyond	Total
Current Capital Approval Request	$0.0	$21.3	$6.3	$1.3	$0.0	$0.0	$0.0	$28.9
Previous Request(s)	0.8	0.6	0.0	0.0	0.0	0.0	0.0	1.4
Total Project Request	0.8	21.9	6.3	1.3	0.0	0.0	0.0	30.3
Operating After-Tax Cash Flow	(679)	(17,017)	(10,235)	2,811	2,828	2,723	50,892	31,323
Net Income	17	310	1,185	1,448	1,395	1,340	19,921	25,616

Hurdle Rate	IRR	NPV	Payback(years)	First 5 Yrs Avg. Net Income	Customer cost (savings)*
6.1%	6.1%	$264	15	$ 871	$36,182

Project Description and Approval

The purpose of this request is to obtain full appropriation for the Midas project.

MEP Project Scope:

- Design a new 120kV to 13.2kV Class RR substation (Midas) in Almont Township
- Construct all below grade elements of the new Midas substation
- Create Class R standards as part of the substation design
- Design and install all new system conduit to facilitate the OH circuit work starting outside of substation property

DO Project Scope:

Construct the above grade elements of the new Midas Class RR substation including testing and commissioning. Substation includes two (2) 15/20/25 120 - 13.2 kV transformers and four (4) line positions, Class RR. The future Midas substation will have provisions for expansion to a Class A substation with installation of a future (12) position PDC. Also included is the transfer and partial conversion of two (2) existing Almont 4.8 kV distribution circuits to four (4) future Midas circuits with both 13.2 and 4.8 kV service. After transfer of the Almont circuits to Midas, the existing Almont substation will be de-commissioned.

[41] *Id.* at pp. 7-10.

[42] Ex MEC-5, Company response to MNSCDE-8.5(c) (S1).

[43] Ex MEC-20, *U-21534 MNSCDE-8.5c(S1)-04 4.8kV CC Almond Relief and Circuit Conversion (Midas).*

DTE management apparently assessed the prudence of this project in March 2021, when the appropriation request was approved, and anticipated a "post investment evaluation" in 2025.[44] Given the timeline, scale, and discretionary nature of conversion projects, DTE should present robust support for conversion projects *at the outset.* That would ensure regulatory review and approval (or disallowance, or recommendations to scale back) of these discretionary conversions projects *before* the Company incurs substantial costs. Moreover, DTE management apparently intends to evaluate this investment through the rear-view mirror lens. There is no reason the regulator should not also receive a post-investment evaluation of conversion projects, once completed.

Q. What are your recommendations for the circuit conversion program?

A. I recommend the Commission moderate post-test year conversions spending and require DTE to provide further support for the program and in particular for its proposed rate of conversions. Consistently, the Commission should reject the Company's proposal to extend conversion spending through the IRM in 2026 and 2027. To that end, the Commission should direct DTE to solicit an independent expert to assess the appropriate pace of conversions. To the extent DTE justifies the pace based on capacity increases, DTE must provide independent analysis showing its EV adoption forecasts are likely; that its assumptions about EV charging behavior (peak vs. off-peak) are accurate; and that adoption forecasts and charging behaviors are associated to geographies, substations, and circuits. DTE must demonstrate the rate impact associated with the pace of 4.8kV circuit conversion, and that the impact is appropriate based on ratepayer interests and the value

[44] *Id.*

received. I also recommend the Commission require DTE to establish and present in its next rate case metrics, such as dollars per circuit mile converted, to budget and monitor circuit conversion costs.

Q. Do you have any recommendations related to proposed conversion projects?

A. Yes. As discussed above, the Commission should clarify and improve the regulatory review process for all large ($10 million or more) voltage conversion projects. DTE should provide robust, project-specific risk-informed cost-benefit analyses for these projects, including a thorough review of alternatives, before substantial capital ($1 million) is invested beyond the conceptual and design phase.

Q. Do you have any recommended disallowances related to circuit conversions?

A. I am not recommending disallowance in this program area in the bridge and test years because DTE's proposed test year spending is for conversions ($78.8 million) and is substantially lower than conversion spending in 2022, 2023, and 2024.[45] However, DTE proposes that circuit conversions would comprise $430 million of IRM spending in 2026 and 2027.[46] DTE's lack of justification for the scope of circuit conversion based on its preferred pace of conversions undermines the prudence of the IRM proposal. The Commission should reject DTE's proposal to include Conversions in the 2026 and 2027 IRM because the Company has supported conversions as a value proposition for ratepayers.

[45] Ex A-12 Sch B5.4, p. 16, line 15 ($104.5 million in 2022; $161.9 million in 2023; $199.2 million in 2024).

[46] Foley Revised Direct at NRF-54; Ex A-33 Sch X1.

Now that DTE has several conversion projects in service, it should have ample data to demonstrate the full actual costs and benefits to ratepayers of voltage conversion projects.

IV. POLE AND POLETOP MAINTENANCE AND MODERNIZATION

Q. Please summarize DTE's Pole and Pole Top Maintenance and Modernization ("PTMM") program.

A. In recent years the Company has strengthened its pole inspection standards, resulting in the Pole and Pole Top Maintenance and Modernization program. In the second half of 2019, DTE changed its standards for pole construction. The new construction standard uses fiberglass crossarms instead of wood crossarms, polymer cutouts instead of porcelain cutouts, and polymer insulators instead of porcelain insulators,[47] along with a few other changes.[48] The changes in the construction standards were significant, leading to a change in the name of the program to add the "Modernization" moniker.

Q. What is your assessment of the Company's decision to increase its pole inspection standards?

A. The increase in pole inspection standards appears reasonable, though the move to inspect pole tops (once every five years) more frequently than poles (once every ten years) is not as common as the Company seems to imply. In my experience, it is very common to inspect pole tops at the same frequency as poles, as it reduces inspection costs (because poles and pole tops can be inspected at the same time). While I do not oppose the five-year inspection standard for pole tops, the Company should have undertaken a benefit-cost

[47] 2023 DGP, Ex A-23 Sch M8, p. 68 of 274.

[48] Ex A-23 Sch M9.

analysis comparing the increased costs of more frequent inspections to the customer benefits of more frequent inspections (the dollar value to customers of the expected reduction in service interruption frequency) before making the change.

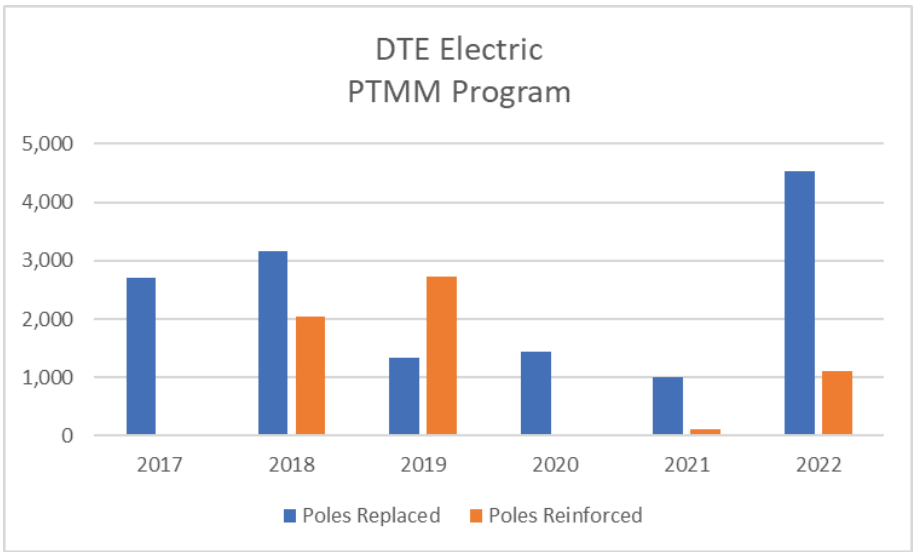
Q. What are the practical implications of new construction standard adoption?

A. New standards are applied to all new construction. This includes not just the construction of a brand new circuit, but to any work completed on existing circuits. For example, the Company's new standard for fiberglass crossarms rather than wood crossarms means that if a pole is replaced, the wood crossarm that may have been in place previously cannot be re-installed; it must be replaced with a fiberglass crossarm, even if the wood crossarm previously installed is in good condition. Similarly, if a crossarm is being replaced, the porcelain insulators on the crossarm cannot be reinstalled; the porcelain insulators on the crossarm must be replaced with polymer insulators even if the porcelain insulators are in good condition. If there is a porcelain cutout installed on the crossarm, it too must be replaced with a polymer version even if the porcelain cutout is in good condition.

Q. Does new standard adoption increase costs?

A. New construction standards can substantially increase costs, and this is why changes in standards are a significant event at most utilities. In my experience changes to construction standards have historically been preceded by workshops attended by personnel from multiple operating regions and departments. Multiple review rounds of edits to the existing standard are completed as the new standard takes shape. Analyses are completed that estimate the incremental benefits (in dollars) and incremental costs of the change to ensure the change is cost-effective. All this is presented to management for formal review and approval.

Changes to pole standards can be particularly costly decisions, as most utilities have so many poles. DTE estimates it operates and maintains 905,000 poles.[49] As identified by MNSC Witness Mr. Ozar in U-21297, the rate of pole reinforcements has fallen and the rate of pole replacements (more costly than pole reinforcement) have increased since the introduction of the increased inspection standards:[50]



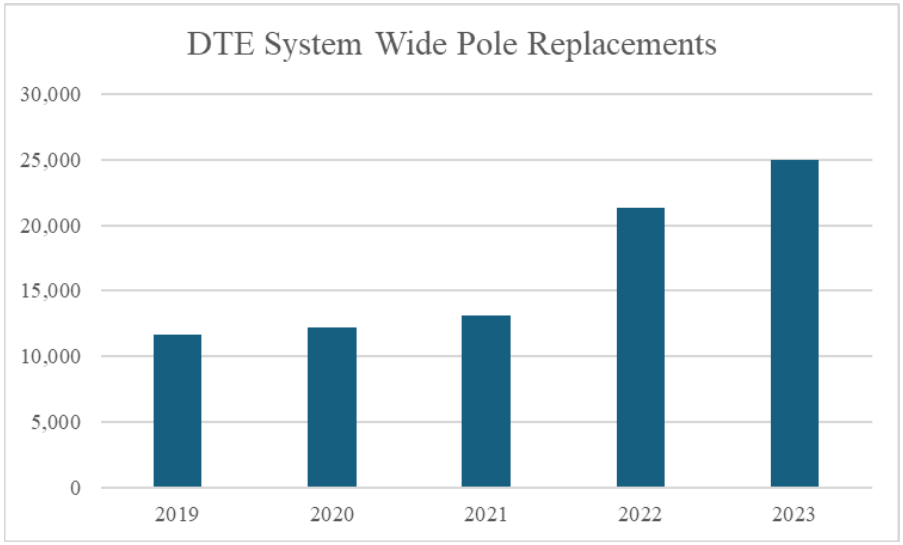
Of course, the new pole inspection and construction standards impact more than just the PTMM program, and indeed the rate of pole replacement has increased across DTE's system in recent years, as indicated by the chart below.[51] In addition, the new

[49] See Company response to MNSCDE 3.16(i) ("The BCA model has 904,986 total poles but does not differentiate between wood and non-wood poles. Approximately 93% of the Company's poles are wood.").

[50] Ex MEC-MEC-13, Case No. U-21297 AGDE-4.103b Narrative + Attachment *U-21297 AGDE-4.103b-01 PTMM and 4.8kV Hardening Metrics 2017-2022.*

[51] See Company response to MNSCDE 3.16(j), p. 2 ("Total quantity of poles replaced within Distribution Operations (including strategic projects): 2019: 11,665 / 2020: 12,202 / 2021: 13,097 / 2022: 21,321 / 2023: 24,996").

construction standard likely increased the cost per pole replaced, creating a multiplier effect on capital spending related to poles.



Q. Did DTE management review and approve a well-supported change to the pole construction standard, with such support including analyses estimating the benefits and costs of the new standard?

A. It does not appear so. The Company failed to provide documentation of such a review or approval despite repeated requests.[52] However, the Company hired an external consultant to complete a cost-benefit analysis after the fact, while DTE was preparing its instant application.[53]

Q. Is the timing of the Company's analysis a concern?

A. It is. DTE solicited a consultant after it decided to increase the pole construction standard, and after hundreds of millions of dollars had already been spent. In my experience, the

[52] Ex MEC-14, Company responses to MNSCDE 3.8(c) + 8.9(c).

[53] Ex A-23 Sch M13, "1898 & Co. Benefit-to-Cost Analysis Modeling whitepaper" (March 6, 2024).

purpose of completing benefit-cost analyses on spending proposals is to make better decisions regarding those proposals *before* costs are incurred. In this case, a benefit-cost analysis on the PTMM program was completed after the fact in an apparent attempt to retroactively justify the change in standards which DTE had already made.[54]

Q. Did you evaluate the PTMM benefit-cost analysis completed by the consultant?

A. Yes, and my concerns about its veracity are substantial. For example, the Company cannot provide the historical failure rates for crossarms, porcelain cutouts, and porcelain insulators, nor can it identify service interruptions, customer counts, or average durations associated with failures from these equipment types.[55] Clearly, when projecting improvements relative to existing construction standards, an understanding of the baseline service interruption risk is critical to have. Not only does the consultant's PTMM benefit cost analysis fail to employ these values, DTE does not maintain the data required to produce these values.

As another example, the PTMM benefit cost analysis overestimates the benefits from avoided costs by assuming that every truck roll avoided (for example, to respond to a pole top equipment failure or a related service interruption) reduces DTE's costs by $2,000.[56] This appears to be a fully-loaded cost, typically estimated by dividing annual

[54] See Company response to MNSCDE 3.8(a) ("The Company collaborated with an independent consulting firm to create a BCA based on methodology utilized by other utilities in many states (such as IN, OH, IL, MD, FL, and OK) to justify distribution investments."). Notably, the programs the firm justified through its analyses in other states had nothing to do with PTMM, and that the "methodology" referenced is generic in nature.

[55] Ex MEC-15, Company responses to MNSCDE 3.15 (c)(i), (ii), 3.23(d); 3.1(a), (b), (c), and excerpt from *Attachment U-21534 MNSCDE-3.1-01 Outages 2017-2023 (Dec. 2023 outages)*.

[56] Ex A-23 Sch M13, 1898 & Co. Benefit-to-Cost Analysis Modeling whitepaper, p. 16.

field crew costs, related service center costs (such as the cost of supervisors), vehicle costs, and all allocated corporate general and administrative costs (such as from human resources, accounting, and regulatory services departments) by a count of truck rolls completed in a year. Many if not most of these costs are fixed. What is needed for this estimate is the marginal cost avoided by a truck roll, which is typically gasoline (for the truck) and perhaps some overtime costs. There is no chance whatsoever that the average marginal cost avoided by a truck roll is anything remotely close to $2,000.

In summary, between the lack of a sound baseline and exaggerated avoided cost estimates, the benefits the model estimates appear to be exaggerated. But the PTMM BCA also understates customer costs. The costs in the model represent the present value of the costs the Company must pay. It does not include the costs customers must pay on top of DTE capital costs, including DTE's interest expense, a rate of return for shareholders, property taxes DTE must pay to local governments, or state and federal income taxes on the profits DTE earns on PTMM capital spending. Between overstated benefits and understated costs, the Company's representation that the upgraded poletop construction standards, or the PTMM program based on those standards, deliver benefits in excess of costs rests on a weak foundation.

Q. What benefit to cost ratio does the PTMM benefit cost analysis indicate?

A. The report never really says. Instead, the report states that of 2,242 circuits modeled, benefits exceeded costs on 95% of these.[57] However, DTE maintains 3,273 distribution

[57] *Id* at 21 ("Figure 5-1 shows a histogram of the benefit-to-cost ratio for the 2,242 circuits modeled. These results

circuits, and the Company's confidential workpaper indicates 2,242 circuits is only about 60% of the Company's total circuits.[58] The report does not indicate what criteria the consultant applied to select a subset of the Company's circuits for its stated conclusion, or why they selected only a portion of circuits to summarize in its whitepaper.

Q. Given these concerns about the new poletop inspection and construction standards, and the PTMM benefit cost analysis, what is your recommendation for PTMM in the Company's instant application?

A. As a result of the upgraded construction standards described, there is a significant jump in costs from the poletop maintenance (PTM) program to the poletop maintenance and modernization (PTMM) program. However, DTE has not supported the reliability impact of PTM vs. PTMM, nor compared that impact to the cost difference between PTM and PTMM. Given that the Company has completed both PTM and PTMM on many different circuits in recent years, an opportunity to complete this critical analysis exists. I recommend the Commission order DTE to present an assessment of the reliability difference between PTM circuits and PTMM circuits using historical data in a way that prevents the comingling of tree trimming benefits, and to calculate the monetary value of the reliability improvements relative to the incremental costs of the new pole top construction and inspection standards. This information is necessary for DTE to support its proposed increasing level of capital spending in the PTMM program.

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indicate a compelling business case for the PTMM program, where 95% (2,124 out of 2,242) of the analyzed circuits have a benefit-to-cost ratio of no less than 1.").

[58] 2023 DGP, Ex A-23 Sch M8, p. 10 of 274; see NDA U-21534 MNSCDE-3.10b-01 PTMM BCA Model, tab "Master Circuit Table", indicating [[ ]] circuits.

Regarding test year spending, DTE has not supported the request to increase spending in the PTMM beyond what was approved in U-21297, which was $63.45 million.[59] The Commission should cap test year spending accordingly. This will ensure customers will not be deprived of benefits in the event the new construction standards prove to be cost-effective.

Furthermore, DTE proposes $350 million in PTMM spending for the 2026 and 2027 IRM.[60] Given the limitations in the PTMM model, and the Company's failure to measure the value and impact of the new poletop construction standards and the PTMM program on which it is based, the Commission should reject DTE's request for PTMM spending in 2026 and 2027 through the IRM.

V. SUBTRANSMISSION REDESIGN AND REBUILD PROGRAM

Q. Please summarize DTE's Subtransmission Redesign and Rebuild program.

A. The Subtransmission Redesign and Rebuild program ("Subtransmission R&R program") is designed to improve the resilience of DTE's subtransmission grid to storms, as well as the redundancy of the subtransmission grid in the rare event that equipment outages, which are different from customer service interruptions, occur. In addition, the Subtransmission R&R program appears to be designed to increase grid capacity. It appears that the Company, when rebuilding subtransmission lines, employs larger conductor than what was in place previously. For subtransmission circuits that include underground segments, this

[59] Case No. U-21297, Dec. 1, 2023, Order, p. 96.

[60] Ex A-33 Sch X1.

means that the underground segments are most likely also upgraded with higher capacity underground cable.

Q. How are equipment outages different from service outages?

A. Subtransmission reliability is measured through equipment outages rather than through standard distribution grid reliability metrics (such as system average interruption duration and frequency). This is because the redundancy built-in to subtransmission design is so significant, and customer service interruptions so rare, as to make service interruptions unhelpful in evaluating subtransmission grid reliability. In fact, of 5,239 equipment outages DTE reported on its subtransmission system from 2019 through 2023, only 26% resulted in an interruption in service to customers.[61] Customer service interruptions from the subtransmission system constituted just 3.9% of all customer minutes of interruption experienced by DTE customers from 2019-2023.[62] Given that subtransmission service interruptions are such a small proportion of DTE's total service interruptions, addressing them with a large-sized Subtransmission R&R program is not effective. Further, customers are already paying for redundant design specifically to reduce the consequences of equipment failure. Projects should be evaluated carefully and individually, with the greatest scrutiny applied to the largest projects, and in a way which reflects the risk reductions already made available through redundant design.

Q. Are Subtransmission R&R projects costly?

[61] Ex MEC-16, Company responses to MNSCDE-3.26(a), (b) and Attachment *U-21534 MNSCDE-3.26-01 Subtransmission Interruptions.*

[62] Total customer minutes of interruption 2019-2023 8,657,536,089 (from Ex 15, *U-21534 MNSCDE-3.1-01 Outages 2017-2023*); total customer minutes of interruption on the subtransmission grid 2019-2023 336,159,815 (from Ex 16, *U-21534 MNSCDE-3.26-01 Subtransmission Interruptions*).

A. Yes, Subtransmission R&R projects can be extremely costly. DTE's Global (project) Prioritization Model ranks 49 Subtransmission R&R projects in its top 138 priority projects. [[ ]][63] Similar to Conversions projects discussed earlier, these are the Company provides slender evidence outlining the full timing, cost, and value of these projects, which typically extend over multiple years.[64] It is difficult to determine the full actual cost to ratepayers resulting from these projects, and even more so to ascertain their quantifiable benefits (or value) to ratepayers.

Q. Does the Subtransmission Redesign and Rebuild program improve resilience?

A. Only indirectly. When rebuilding circuits, DTE chooses larger conductor, and replaces wood poles with steel poles. Larger conductor and steel poles are less susceptible to storm damage than smaller conductor and wood poles. However, wind and ice comprised just 1.3% of subtransmission equipment outages from 2019 to 2023.[65]

Q. How does the Subtransmission R&R program improve redundance and increase capacity?

A. As indicated above, the subtransmission grid is designed with built-in redundancy. This is known as "n-1" design, and means that the subtransmission grid will continue to carry

[63] Ex MEC-17, Company Response to MNSCDE-1.8(a) + Attachment NDA CEII U-21534 MNSCDE-1.8a DTEE GPM / GPM Results Tab / Col A to AB ("blue").

[64] See Ex A-23 Sch M6 pp. 192-315; Ex A-12 Sch B5.4, p. 14 lines 5-25 (projects in service through 2025), p. 15 lines 66 to 75 (projects in service beyond 2025).

[65] Ex MEC-16, U-21534 MNSCDE-3.26-01 Subtransmission Interruptions.

power to distribution substations over back-up supply routes in the event of an equipment outage on the day-to-day supply routes. While not all distribution substations have a back-up source of subtransmission supply, in my experience the vast majority typically do.[66] Of those distributions that do have a back-up source of supply, the back-up capacity is not always adequate for all hours of the year. For example, while back-up capacity may be adequate for 97% of the hours in a year (as an example), there may be some hours of the year when the back-up capacity is inadequate. Should an equipment outage occur during the 3% of the hours of the year[67] when back-up capacity is not adequate – usually, summer weekday afternoons – a service interruption can occur despite the redundant design available from back-up supply routes.

What this means is that violations of a redundancy design standard are not absolute (yes or no), but are represented by a range of likelihoods. The Company estimates that one-third of its subtransmission circuits violate capacity planning criteria.[68] The Subtransmission R&R program aims to improve redundance and reduce planning criteria violations through projects to increase subtransmission circuit capacity.

Q. What is the implication of the assertion that one-third of DTE subtransmission circuits violate capacity planning criteria?

[66] DTE did not provide a list for evaluation in discovery, citing critical energy infrastructure information. See Company response to MNSCDE-5.2(b)(i) ("The list of substations on radial lines would provide a clear map of the Company's system which would negatively affect national security, economic security, public health or safety, or any combination of such matters.").

[67] Three percent is used as an example because peak loading conditions typically occur between 3 and 7 pm (4 hours) on 65 summer weekday afternoons (from June 1 to August 30). Three percent of 8,760 hours in a year is 260 hours, or 65 summer weekday afternoons multiplied by 4 hours each.

[68] Direct Testimony of Satvir S. Deol at SSD-51:7.

A. While not ideal, like the problem with the design of the Company's 4.8kV circuits with respect to the risk of a downed wire remaining energized, DTE's subtransmission system has likely been in its current condition (with a significant proportion of its circuits in violation of planning criteria) for several decades. The question is, on which subtransmission circuits are the risks the greatest, and how quickly should they be addressed? When measuring the size of the risks, DTE must support its analysis and conclusions using risk-informed benefit-cost analyses. As described in Mr. Alvarez's testimony, risk-informed benefit-cost analyses monetized the risk reduction available from a specific project in dollars. Once the risk reduction available from a project has been monetized in dollars, the risk reduction value can be compared to project costs to aid decision-making.

Q. Does DTE complete risk-informed benefit-cost analyses on proposed Subtransmission R&R projects?

A. No. DTE does not complete any type of benefit-cost analysis on proposed Subtransmission R&R projects, let alone analyses that monetize risk reduction value in dollars.[69] Nor does DTE complete benefit-cost analyses on alternatives available to proposed projects, thereby permitting comparisons as to the "bang for the buck" available from each alternative. In fact, the Company does not always identify alternatives to subtransmission projects proposed.[70] Particularly given the large size of many Subtransmission R&R projects, these failures are unacceptable.

[69] Ex MEC-18, Company response to MNSCDE 5.4 (a),(b), (c); see also Ex A-13 Sch M6.

[70] Ex MEC-19, U-21534 MNSCDE-8.5a-01 Project Alternatives.

Q. What do you recommend for the Company's Subtransmission R&R projects and program?

A. With no type of benefit-cost analyses completed on Subtransmission R&R projects indicating that the value of risk reductions exceeds the costs of the projects to customers, these projects are unsupported. Absent the Company providing a comprehensive and unbiased risk-informed benefit-cost analysis indicating that Subtransmission R&R projects are cost effective, DTE has not demonstrated these projects are reasonable and prudent investments. I recommend the Commission disallow cost recovery on all such projects the Commission has not already approved. In 2024 and 2025, DTE projects bringing three such projects online, and adds them to rate base in the instant application. The three projects – Tie 4105 Phase 3, Tie 4105 Phase 4, and Trunk 3509 – total $28.15 million, and I recommend the Commission remove these projects from 2024 and 2025 test year revenue requirement calculations.

Furthermore, DTE proposes to spend $120 million on the Subtransmission R&R program in IRM program years 2026 and 2027.[71] Given the lack of support the Company provides for Substation R&R projects, the Commission should deny the Company's request to include this program in the 2026 and 2027 IRM.

Finally, going forward, the Commission should improve the regulatory review process for all large ($10 million or more) Subtransmission R&R projects. DTE should provide robust, project-specific risk-informed cost-benefit analyses for these projects, including a thorough review of alternatives, *before* substantial capital ($1 million) is

[71] Ex A-33 Sch X1.

invested beyond the conceptual and design phase. Absent a robust demonstration that the project provides positive value to ratepayers, the Company has failed to carry its regulatory burden.

VI. DISTRIBUTION AUTOMATION PROGRAM

Q. Please describe DTE's Distribution Automation program.

A. DTE's Distribution Automation program is designed primarily to improve reliability. DTE's grid consists of many tie lines between circuits which can be reconfigured to re-route power in the event of a fault. Grid reconfiguration using switches and ties can restore power to some customers while the fault is being repaired (through customers in the immediate vicinity of the fault must wait until the repairs are complete). Typically, crews are sent to throw switches to complete the reconfiguration. Distribution Automation employs sophisticated switches which automatically reconfigure the grid, avoiding time spent by dispatchers (trying to figure out the best reconfiguration) and crew travel time (to throw the switches). Distribution Automation can therefore reduce the duration of service interruptions for some customers initially impacted by a fault. The sophistication of the switches adds some value too; remote communication and control are standard, and the switches incorporate line sensors for monitoring grid status with precision (voltage, current, frequency, phase balance, etc.).

Q. What are the drawbacks of Distribution Automation?

A. Automated switches may operate incorrectly, requiring crews to drive from switch to switch anyway. In storm situations, where damage is widespread, intact circuits from which to reroute power may not be available, negating Distribution Automation value.

The switches are costly, and the law of diminishing returns applies; in my experience, one tie line/switch per circuit is typically optimum, but I have observed investor-owned utilities install automatic switches beyond the point of diminishing return.

Distribution Automation is most often cost-effective when tie lines between circuits have already been built. While the automated switches are costly to install, the construction of new tie lines is orders of magnitude more costly than switch installation. Care should be taken to ensure tie lines are not being built where the benefits fail to outweigh the costs. The benefits of Distribution Automation relative to costs can also be impacted by circuit customer counts and customer mix (commercial vs. residential). Finally, Distribution Automation is a solution that addresses a symptom (service interruptions), not root causes (such as vegetation contact). The bottom line is that Distribution Automation is not a cure-all and is only appropriate for some circuits.

Q. Did you review DTE's Automation Prioritization tool?

A. Yes, the tool is a step in the right direction. But, as with the Company's Global Prioritization Model ("GPM"), the Automation Prioritization tool is not designed to quantify benefits in dollars, enabling a comparison to costs. Like the GPM, the Automation Prioritization tool appears to rank circuits by benefit score per dollar rather than benefit dollars relative to costs. Further, due to the tool's Critical Energy Infrastructure Information ("CEII") status, it was provided in online view only, precluding an understanding of the weights assigned to various tool inputs in calculating a score.[72] Again, a risk-informed, dollar-denominated benefit-cost analysis is what is needed.

[72] NDA CEII U-21534 MNSCDE-12.13-01 Automation Prioritization Analysis (credentialed online access only; not available for editing, printing, or downloading).

Q. Does Distribution Automation also offer safety benefits?

A. Not typically. But I understand that DTE is proposing to employ automated switches to address the energized wire down situation caused by the design of its 4.8kV circuits. As discussed earlier, the "no neutral wire" design of DTE's 4.8kV circuits increases the risk that a downed wire will remain energized. The more sophisticated capabilities of the automated switches could be employed to reduce this risk. However, DTE provides no measurable safety basis to support the reasonableness and prudence of hundred-million-dollar annual spending requests for Distribution Automation, absent a comprehensive analysis and related cost justification.

Q. Why not?

A. For three reasons. First, as identified earlier, the energized wire down risk on DTE's 4.8kV circuits has existed for the last 75-120 years, since the circuits were constructed. As automated switches have been commercially available for more than a decade, DTE's sudden sense of urgency is unconvincing and warrants scrutiny. Second, the Company is already pursuing multiple costly programs to reduce the likelihood that any wires will fall, let alone energized wires. These programs include the program to remove DPLD wire, the pole-top management program, and the enhanced tree trimming program. Third, the costly automated switches are voltage specific. A 4.8kV switch cannot be used on a 13.2kV circuit. As the automated switches have a design life of 20-25 years or more, installation on 4.8kV circuits the Company aspires to move to 13.2kV in the next 15 years will render money spent on automated 4.8kV switches largely wasted.

Q. What are your recommendations regarding Distribution Automation?

A. First, the Commission should require the Company to develop a benefit-cost model to govern Distribution Automation deployment on a circuit-specific basis. Such a model should use circuit characteristics and service interruption history to estimate Distribution Automation benefits, in dollars, on a circuit-specific basis. As I indicated above, asserting safety benefits, without supporting analysis, is insufficient basis for this program. Safety risk reduction value estimates should be based on historical data, circuit-specific if available, on counts of wires down; the ratio of instances in which downed wires were energized; the ratio of safety incidents occurring from energized wire down events; and an estimate of the consequences (in dollars) per safety incident. The Distribution Automation circuit model should also reflect all costs, including the cost to construct tie-lines between circuits for any specific circuit deployment plan. The need to construct a tie-line is likely to render almost any circuit-specific Distribution Automation deployment plan cost-ineffective.

Second, until a circuit-specific Distribution Automation model can be developed, I recommend the Commission limit the Distribution Automation deployment budget to the annual amount the Commission approved in U-21297 ($27.167 million less a 10% reduction recommended by Staff).[73] This amount is sufficient to deploy Distribution Automation in cost-effective instances while reducing the likelihood it will be deployed cost-ineffectively.

[73] Case No. U-21297, Dec. 1, 2023, Order, p. 122-23; Case No. U-21297, Ex A-12 Sch B5.4 p. 12 lines 9, 10.

Finally, the Company proposes Distribution Automation for $285 million in IRM cost recovery in 2026 and 2027.[74] Given the significant variation in cost-effectiveness by circuit and other limitations, and absent a robust demonstration to the contrary, the Commission should reject the Company's request to include Distribution Automation spending in the proposed extended and expanded rider IRM.

VII. STRATEGIC AND SERVICE OVERHEAD TO UNDERGROUND PILOT

Q. Please summarize DTE's Strategic and Service Overhead to Underground Pilot.[75]

A. The program replaces overhead lines, and the overhead service drops that lead from these lines to customer premises/meters, with underground lines and services. The program is targeted to overhead lines in "backlot" locations, in which DTE crews must cross into customers' yards, without the help of bucket trucks, to maintain overhead lines.

Q. Would replacing overhead lines in customer backyards with underground lines offer reliability and safety benefits?

A. To some degree. But underground lines are subject to reliability risk from flooding and careless excavation, and subject to safety risk from both excavation and contact voltage. In short, undergrounding is not the panacea many perceive it to be. But most critically, undergrounding overhead lines and service drops is prohibitively expensive. The extreme costs of undergrounding must be considered in any discussion of the benefits. The Appoline pilot cost $14,672.13 per customer, while the Buffalo-Charles pilot cost

[74] Ex A-33 Sch X1.

[75] DTE's use of the phrase "pilot" appears to be a misnomer. The Company has already completed two such pilots, and both indicated that benefits did not exceed Company costs, let alone the costs customers will have to pay.

$37,908.50 per customer.[76] These costs per customer are typical in our experience, and the results of DTE's benefit-cost analysis ($0.58:$1 for the Appoline pilot and $0.37:$1 for Buffalo-Charles pilot) are in line with published research on the topic.[77]

Q. Do you recommend the Commission eliminate this program?

A. Yes. The undergrounding of overhead lines is cost-ineffective, and additional pilots are unlikely to deliver different results.[78] I therefore recommend the Commission remove $16.02 million the Company proposed for this program in the 2025 test year. I also note that while the Commission disallowed $1.9 million in 2024 test year capital spending for the program in DTE's last rate case,[79] the Company projects spending of $15.64 million in 2024. I recommend the Commission disallow the full amount from recovery from customers for the reasons just discussed.

VIII. THE COMMISSION SHOULD NOT EXTEND AND EXPAND THE IRM FOR THE BREAKER AND URD REPLACEMENT PROGRAMS.

Q. Besides the programs you have already discussed, are there any other programs included in DTE's requested expansion of the IRM into 2026 and 2027?

[76] The Appoline pilot ($895,000 cost) served 61 customers, while the Buffalo-Charles pilot ($17.4 million cost) served 459 customers. See Ex A-23 Sch M13 pp. 22-23.

[77] Larsen P., *A Method to Estimate the Costs and Benefits of Undergrounding Electricity Transmission and Distribution Lines*. Lawrence Berkeley National Laboratory report LBNL-1006394, p. 35. Accessed July 25, 2024, available at https://eta-publications.lbl.gov/sites/default/files/lbnl-1006394_pre-publication.pdf (showing ratio of $0.30:$1).

[78] *Id.*

[79] Case No. U-21297, Dec. 1, 2023, Order, p. 104; U-21297, Ex A-12 Sch B5.4, p. 11 line 109.

A. Yes, DTE also proposes to expand and increase spending in the Breaker and URD Replacement programs.[80] The scope of this spending – and increased spending – is smaller than the programs just discussed.

Q. Did you evaluate these programs in preparing your testimony in DTE's last rate case?

A. Yes, I did. I found neither program delivered benefits to customers in excess of costs to customers.[81]

Q. Has your finding regarding these programs changed?

A. No.

Q. Should the Commission approve DTE's request to extend and expand the IRM for these two program areas?

A. No, it should not. Not only have my analyses found these programs to be cost-ineffective, as discussed by Mr. Alvarez, there are multiple inherent challenges with rider programs that authorize spending years into the future, the result of which is a regulatory process that shifts risk to ratepayers, notwithstanding the significant information and resource asymmetry between the utility and ratepayers. Moreover, in U-21297, while the Commission approved 90% of the Company's proposed spending for each program. For both programs, the Commission requested more evidence to support the investments – including evidence that approved investments actually contribute to reductions in the

[80] Ex A-33 Sch X1.

[81] Case No. U-21297, Stephens Direct, 6 TR 3386-91 (Circuit Breaker Replacement) and 3391-94 (URD Cable Replacement).

frequency and duration of outages.[82] The Company has not provided cost-benefit analyses to support these investments. The Commission should not approve inclusion of these programs in the 2026 and 2027 IRM.

IX. REVIEW, SUMMARY, AND CONCLUSION

Q. Please summarize your testimony and recommendations.

A. This testimony began with the overall theme that benefit-cost analyses should be employed to make decisions regarding discretionary capital programs, and identified all capital programs examined in this testimony as discretionary. The introductory section continued with three key observations:

- Storm response and vegetation management – not equipment condition – have driven the Company's historically poor (relative to peers) reliability performance.
- The reliability improvements DTE calculates from many of its capital programs conflate benefits from the programs with benefits from the tree trimming that are part and parcel of the programs and are thus significantly exaggerated.
- Massive increases in capital spending in recent years have not improved DTE reliability performance, casting doubt as to the effectiveness of capital spending as a solution to relatively poor reliability performance.

My testimony addresses six discretionary capital spending programs DTE presents in its instant application. A seventh capital spending program – Grid Automation Telecommunications – is addressed in AG-MN Witness Alvarez's testimony but presented in the table below for convenience. I also summarily address the Company's request to expand the IRM for two equipment replacement programs. I provided a summary of my

[82] Case No. U-21296, Dec. 1, 2023, Order, pp. 99-101.

recommendations in the table at the start of my testimony; recommended disallowances are summarized in Exhibit MEC-11 and in the table below:

AG-MN 2024 / 2025 Test Year Reductions ($ in millions)	Reduction in 2024	Reduction in 2025 Test Year
4.8kV Hardening		
DTE Requested '24/ '25 Test Year	80.000	125.000
AG-MN Recommended Adjustment	(73.333)	(81.800)
AG-MN Recommended '24 / '25 Test Year Spend	6.667	43.200
Pole and Poletop Maintenance and Modernization		
DTE Requested '25	n/a	121.000
AG-MN Recommended Adjustment	n/a	(57.550)
AG-MN Recommended '25 Test Year Spend	n/a	63.450
Distribution Automation		
DTE Requested '25	n/a	125.625
AG-MN Recommended Adjustment	n/a	(101.176)
AG-MN Recommended '25 Test Year Spend	n/a	24.449
Strategic & Service Line OH to UG Pilots		
DTE Requested '24/ '25 Test Year	15.644	16.019
AG-MN Recommended Adjustment	(15.644)	(16.019)
AG-MN Recommended '24 / '25 Test Year Spend	0.000	0.000
Grid Automation Telecommunications		
DTE Requested '24/ '25 Test Year	16.900	15.000
AG-MN Recommended Adjustment	(16.900)	(15.000)
AG-MN Recommended '24 / '25 Test Year Spend	0.000	0.000
Subtransmission Redesign and Rebuild Disallowances		
Tie 4105 Phase 3 (projected to be in service in 2024)	(19.274)	0.000
Tie 4105 Phase 4 (projected to be in service in 2025)	0.000	(2.808)
Trunk 3509 (Projected to be in service 2024)	(6.062)	0.000
Total Subtransmission Redesign and Rebuild Disallowance	(25.336)	(2.808)

2024 /2025 Test Year Reduction Summary	**2024**	**2025**
4.8kV Hardening	(73.333)	(81.800)
Pole and Poletop Maintenance & Modernization	n/a	(57.550)
Distribution Automation	n/a	(101.176)

Strategic & Service Line OH to UG Pilots	(15.644)	(16.019)
Grid Automation Telecommunications	(16.900)	(15.000)
Subtransmission Redesign and Rebuild	(25.336)	(2.808)
TOTALS	**(131.213)**	**(274.353)**

Q. Does this conclude your testimony?

A. Yes, it does.

MS. ANDREWS: Thank you. Next, I would move to bind into the record the Rebuttal Testimony of Douglas Jester on behalf of the Citizens Utility Board of Michigan, the Sierra Club, Michigan Environmental Council, and Natural Resources Defense Council. Mr. Jester's rebuttal testimony consists of a cover page, table of contents, and eight pages of question and answers, and there are no exhibits, rebuttal exhibits.

JUDGE WALLACE: Thank you. Is there any objection to binding in the rebuttal testimony of Mr. Jester?

Hearing none, the testimony is bound in.

(Testimony bound in.)

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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

REBUTTAL TESTIMONY OF DOUGLAS B. JESTER

ON BEHALF OF

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

August 16, 2024

REBUTTAL TESTIMONY OF DOUGLAS B JESTER FOR MNSC
CASE NO. U-21534

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II. REBUTTAL TO STAFF EV TESTIMONY 1

I. INTRODUCTION AND QUALIFICATIONS

Q. State your name, business name and address.

A. My name is Douglas Jester, and I am a Managing Partner of 5 Lakes Energy with mailing address PO Box 869, Northport MI 49670.

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

A. I am appearing here as an expert witness on behalf of Citizens Utility Board of Michigan, Sierra Club, Michigan Environmental Council, and Natural Resources Defense Council, collectively referred to as "MNSC".

Q. Are you the same Douglas Jester who provided direct testimony in this proceeding?

A. Yes, I am.

II. REBUTTAL TO STAFF EV TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the direct testimony of Staff witnesses Allan D. Freeman and Nicholas M. Revere regarding electric vehicles ("EVs").

Q. What aspects of witness Freeman and Revere's testimony will you address?

A. I am rebutting Mr. Freeman's testimony regarding:

a) the consideration of DTE Electric's Transportation Electrification Plan ("TEP") in this and other rate cases;

b) his recommendation to disallow $8 million of DTE Electric's proposed spending on eFleet and Business Charger rebates; and

c) his recommendation to disallow $1 million of DTE Electric's proposed spending for Residential Customer rebates.

I am rebutting Mr. Revere's testimony regarding his recommendation to require customer-level cost benefit analyses for "Fleet – Other DCFCs" and "Fleet – Other Level 2" rebate recipients.

Q. What does witness Freeman testify regarding consideration of DTE Electric's Transportation Electrification Plan?

A. Witness Freeman represents that the Staff view is that the discussion and evaluation of DTE Electric's TEP be deferred to a future date and proceeding.[1] He specifically asserts that "The Company's current rate case is not the appropriate venue for discussion and criticism of its TEP."[2] I am not a lawyer, but that assertion appears to deny intervenors the ability to examine the evidence supporting proposed spending and accounting practices in the present case and would therefore deny due process rights of affected persons. Until and unless the Commission provides a different venue in which discovery, testimony, and cross examination are available in a contested case culminating in Commission decisions on matters presented in the TEP, the Commission should not limit the consideration of the TEP in the rate case wherein the Commission might approve spending and accounting

[1] Direct testimony of Allan D. Freeman, 10:5-6.

[2] Direct testimony of Allan D. Freeman, 7:9-10.

authorizations.

Witness Freeman's rationale is, in part, that "Staff proposed to adopt a similar strategy as the Commission is employing in Case No. U-20147 for its examination of distribution plans."[3] My perspective as a frequent participant in rate cases on subjects that are covered in distribution plans filed in U-20147 is that that process is not working well. MNSC comments in docket U-20147 thoroughly present our perspective on the efficacy of the current distribution plan process.[4] In short, consideration of distribution plans in a non-contested case that are then used as the basis for utility proposals in rate cases has not simplified rate cases nor substantially improved utility accountability for results.

Q. How should the Commission respond to the Staff recommendation that the DTE Electric TEP not be considered in this case?

A. The Commission should reject that recommendation and consider the TEP in this case.

Q. What is the basis for witness Freeman's recommendation to disallow $8 million of DTE Electric's proposed spending on eFleet and Business Charger rebates?

A. Witness Freeman states:

> "The Business and eFleet Charger Rebates $16 million request is the foundational piece of the Company's overall $24,980,000 proposed EV budget request. Staff is uncomfortable with this large, requested amount. It represents a significant increase from past rebate programs. Instead, Staff would like to see the Company implement a scaled down rebate effort. By moving at a more deliberate speed, DTE Electric would still be able to discover if its revised rebates plans accomplish their intended goals."

Q. What is your response to this recommendation by witness Freeman?

A. The Commission should reject this recommendation.

First, the Commission should note that DTE Electric's benefit-cost analysis ("BCA"), which I testified in direct testimony is a ratepayer impact analysis and not a benefit-cost analysis, clearly shows that DTE Electric and therefore its non-participating customers obtain revenue from EV adoption that exceeds the cost of providing charging services.[5] Thus any barrier to EV adoption harms non-EV customers by increasing future rates.

Second, DTE proposes to defer recovery of all rebate spending as a regulatory asset. Thus, there is no effect of the proposed Business and eFleet Charger Rebates on the rates to be adopted as an outcome of the present case. Thus, if actual spending on these rebates is less than projected by DTE Electric, those projected costs will not be recovered. There is no risk to customers that DTE Electric will receive revenue to pay for these rebates without the rebates actually being paid.

Third, each of the Business and eFleet Charger rebates proposed by DTE Electric is likely to occur only as a result of EV adoption driving demand for charging. Each of these rebates requires material investment by the charging host that they are unlikely to make without reasonable expectation of usage. It is therefore unlikely that DTE Electric will actually pay out rebates inconsistent with EV adoption and consequent charging revenues to DTE Electric that will more than cover the rebates. This can be reviewed and confirmed when the deferred costs are rolled into future rates and the amortization period can be adjusted

[5] Direct testimony of Pina Bennett, PB-56:17 through PB-58:5.

to ensure that these EV charging investments are paid for by EV charging revenues.

Q. What is the basis for witness Freeman's proposal to disallow $1 million of DTE Electric's proposed spending on Residential Customer Rebates?

A. The Commission should note that the proposed Residential Customer Rebates are targeted to low-income households.[6] Witness Freeman asserts:

> "Staff agrees with DTE Electric that the low-income segment faces unique challenges for EV adoption and infrastructure. The Company is proposing some changes to its existing EV programs to better focus on this segment. Before awarding the full $3,126,000, Staff would like to see if the Company's efforts successfully address these challenges. If the revised programs have a real impact, DTE Electric can seek additional funding in a subsequent rate case. Consequently, Staff recommends a $1,000,000 disallowance."

Q. What is your response to this recommendation by witness Freeman?

A. As is the case for the eFleet and Business Charger rebates discussed above, these Residential Charger Rebates will only be spent if qualifying households are acquiring EVs, and when they acquire EVs the charging revenues should pay for the rebates. Because recovery of these rebates will be deferred to a regulatory asset, there is no risk of rates including funding of rebates that are not paid out. Therefore, this disallowance is not warranted.

Q. Do you have any further observations regarding the testimony of Witness Freeman?

A. Yes. The specific recommendations of witness Freeman reflect an invalid framing of EV programs by Staff. They appear to view EV program spending as costly to other customers.

[6] Direct testimony of Pina Bennett, PB-37, Table 8.

In fact, EV adoption dilutes rates for other customers to the extent that EV charging revenues exceed utility costs for EV programs, power supply for EVs, and distribution system costs for EV charging. So long as that condition is satisfied, all utility customers are better off if EV adoption is rapid. Thus, there should not be functional quantitative limits on EV charging programs, but rather a clear linkage to EV adoption that assures that all costs of EV programs are ultimately paid for by EV charging revenues.

Q. What is the basis for Witness Revere's recommendation that DTE perform individual customer-level benefit cost analyses for Fleet customers and to require that each project produce net ratepayer benefits?

A. Witness Revere proposes that the net benefits of the "Fleet – Other DCFCs" and "Fleet – Other Level 2" presented by DTE Electric in its direct testimony can be achieved with "proper project selection" but that to ensure the claimed benefits a cost-benefit analysis should be performed on each potential project to ensure that the "expected benefits to the ratepayers supporting the program through rates from the increased grid utilization outweigh the costs of any rebates or increased system costs creating upward pressure on rates".[7]

Q. What is your concern regarding Witness Revere's testimony on this matter?

A. As I discussed in my direct testimony in the present case, the "benefit-cost analysis" provided by DTE Electric is not a benefit-cost analysis, but a ratepayer impact analysis. Witness Revere's testimony on this topic reflects that his view is that only positive

[7] Direct testimony of Nicholas M. Revere, 7:1-8.

ratepayer impact, in the form of diluted rates for all other customers, is a net benefit. Witness Revere would apply that standard to charging infrastructure for individual fleet customers using either DCFC or Level 2 chargers. While I mostly agree with his view that utility programs supporting transportation electrification should be tailored to avoid or limit net cost to other customers, I do not agree that this criterion should be applied to each instance of charging infrastructure.

I appreciate that Witness Revere now appears to accept my long-standing argument that network effects are important, and that public charging infrastructure need not provide full cost recovery for each charging site. His view appears to be that the criterion of net ratepayer benefits need only apply to the public charger programs in aggregate but not to each charging site, while my testimony is that public charging program costs may also be justified by net revenue from all public and private charging.

Regarding utility support for private fleet charging, other than for school busses and transit vehicles, I would concur with Witness Revere's view that these facilities do not provide significant network effects that warrant consideration of net revenue from private charging as an offset to public charging costs. However, I view a net benefit to other customers from the *overall* fleet charging program as sufficient and appropriate.

The addition of fleet charging in any given location is subject to the same considerations that I raised in direct testimony with respect to all charging. If EV charging is projected to be common, the costs of utility distribution system upgrades should be socialized and those socialized costs should be netted out of aggregate charging revenue before considering that the net revenue from individual chargers is available for rebates or other support for

individual customers. If each individual charging installation is subject to cost recovery, substantial inequities may result. For example, a fleet charging facility might not trigger an upgrade of a primary circuit because it has adequate capacity while a fleet charging facility in another location or a subsequent fleet charging facility on the same circuit might trigger an upgrade because of EV charging already situated on that same shared distribution facility.

Fleet charging may have particularly high societal benefits that Witness Revere excludes from consideration, and ignoring those benefits while requiring a positive ratepayer impact for individual fleet charging facilities may do significant harm to certain communities. For example, a fleet charging location that supports significant local heavy-duty vehicle traffic might have very large local emissions and health effects for modest miles traveled that would mean modest incremental electricity sales. For many environmental justice communities, these types of facilities are key issues. Examples of these types of facilities are ports, intermodal facilities, transloading facilities, drayage operations at logistics centers, or trucks that transport parts to assembly plants. Because Staff would exclude these types of benefits from consideration in a site-specific benefit-cost analysis, I recommend that the Commission not require each individual facility to produce net revenue to the utility in order to partake in utility transportation electrification programs.

Q. Does that complete your rebuttal testimony?

A. Yes.

MS. ANDREWS: Next, your Honor, on stipulation of the parties and in lieu of crossing witnesses, MNSC have seven exhibits that we'd like to move for the admission. These consist of Exhibits MEC-69, MEC-70 -- would you like me to describe each one as I go or just --

(Multiple speakers.)

COURT REPORTER: I'm sorry. We do need a description of each for the index. Thank you.

MS. ANDREWS: I'll go ahead and describe each. O.K. Exhibit MEC-69, which is the Company's responses to MNSCDE-20.12, 20.13, and 20.14. Do you want to do these one at a time or should I just go through?

JUDGE WALLACE: Just go through all of them.

MS. ANDREWS: O.K. For the admission of Exhibit MEC-70, which consists of the Company's Annual Tree Trim Reports from 2020, '21, '22 and 2023. Exhibit MEC-122, which consists of the Company Response to MNSCDE-20.3, together with an excerpt from the attachment which is pages 1, and 45 through 53 [sic] of the excerpted attachment; Exhibit MEC-123, which is the Company's Response to MNSCDE-20.4, together with the referenced attachment; Exhibit MEC-124, which is the Company's Response to MNSCDE-20.5, together with the

Company's attachment referenced in the response; Exhibit MEC-125, which is the Company's Response to MNSCDE-19.1, subparts a, b, and c; and finally, MEC-126, which is the Company's Response to MNSCDE-20.16.

JUDGE WALLACE: Thank you, Ms. Andrews. Is there any objection to the admission of Exhibits MEC-69, MEC-70, MEC-122, MEC-123, MEC-124, MEC-125, or MEC-126?

Hearing none, those exhibits are admitted.

MS. ANDREWS: Thank you, your Honor. Nothing further from MNSC.

JUDGE WALLACE: Thank you. O.K. Next, Mr. Ooms.

MR. OOMS: Thank you, your Honor. At this time, and in accordance with the stipulation of the parties, I would move first on behalf of the Michigan Energy Innovation Business Council, the Institute for Energy Innovation, and Advanced Energy United to bind in the Direct and Rebuttal Testimony of Dr. Laura S. Sherman. Her direct testimony consists of a cover page, a table of contents, and 65 pages of questions and answers, and it exists in both confidential and public redacted forms. Her rebuttal testimony consists of a cover page, a table of contents, and 15 pages of

questions and answers. She also sponsored with her direct testimony Exhibits MEIU-1 through MEIU-21, and she sponsored Exhibit MEIU-32 with her rebuttal testimony. I will note that Exhibit MEIU 19 is a confidential exhibit.

JUDGE WALLACE: O.K. Can you just list those again, MEIU-1 through MEIU-21?

MR. OOMS: Correct, your Honor.

JUDGE WALLACE: And then MEIU-32.

MR. OOMS: 32.

JUDGE WALLACE: O.K. All right. Is there any objection to binding in the direct and rebuttal testimony of Dr. Sherman, noting that some of the -- that the direct testimony includes a confidential and public version?

Hearing none, the direct and rebuttal testimony is bound in.

Is there any objection to the admission of Exhibits MEIU-1 through MEIU-21, noting that MEIU-19 is a confidential exhibit, and then MEIU 32?

Hearing none, those exhibits are admitted.

(Public Direct and Rebuttal Testimony bound in.)

(Confidential Direct Testimony found on Page 5312 of the Confidential Record.)

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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. TRANSPORTATION ELECTRIFICATION

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,

[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

[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

[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

[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

[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

[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]

[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

[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,

[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%20201808 02.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

[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

[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]

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.

[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

[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

[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)),

[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

[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.

[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. C&I BATTERY STORAGE PILOTS

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]

[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.

[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

[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

[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

[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.

4891-2246-3184, v. 6

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**

REBUTTAL TESTIMONY AND EXHIBIT

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. Are you the same Dr. Laura S. Sherman who provided direct testimony in this proceeding?

A. Yes, I am.

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

A. Yes, I am sponsoring the following exhibit:

- Exhibit MEIU-32 (LSS-22): Discovery Response EVgo-AG-1

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to certain aspects related to electric vehicles ("EVs") in the direct testimony of Staff witness Allan D. Freeman, in the direct

testimony of Staff witness Nicholas M. Revere and in the direct testimony of Attorney General witness Sebastian Coppola.

II. REBUTTAL OF WITNESS FREEMAN

Q. According to Staff witness Freeman, how should the Commission address the Company's Transportation Electrification Plan (TEP)?

A. In direct testimony, witness Freeman identifies that

> Unlike rate cases which typically involve a single year, a TEP examines an intermediate time frame in the future. The TEP docket is intended to create dialogue among all interested parties. The TEPs are informational only and are not intended for cost recovery. A regulated electric utility can only recover its costs in a traditional rate case.[1]

However, witness Freeman goes on to state that

> The Company's current rate case is not the appropriate venue for discussion and criticism of its TEP. Rates cases are increasingly becoming more complex and have a strict time frame. Instead, Staff proposes to adopt a similar strategy as the Commission is employing in Case No. U-20147 for its examination of distribution plans. Staff will work with the Company to set up a process for all interested parties to review and comment on their TEP. Additionally, there would be a period for any reply comments. This proposed schedule would be filed in Case No. U-21538. Such a process would allow for a more robust and holistic TEP conversation outside of the restrictions found in a rate case.[2]

[1] Direct Testimony of Allan D. Freeman on behalf of Michigan Public Service Commission Staff ("Freeman Direct"), Case No. U-21534, p. 6.

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

Q. How do you respond to this proposal?

A. I am concerned that the process that witness Freeman envisions will not allow adequate feedback on and evaluation of utility TEPs. As noted by witness Freeman, the Commission currently employs a similar process in Case No. U-20147 for the examination of distribution system plans. In that docket, the Commission set a schedule for comments and reply comments on the most recent utility distribution system plans.[3] Comments were due, for example, in the open docket (Case No. U-21047) on DTE Electric's Distribution Grid Plan on March 15, 2024 and reply comments were due on May 24, 2024. In the midst of that process, the Company filed direct testimony in this case, its current general rate case (Case No. U-21534), on March 28, 2024.

Although not the focus of my direct testimony, I am aware that the Company included a number of proposed expenditures in this general rate case that are distribution grid investments and are described in its Distribution Grid Plan. However, given the timing of comments and reply comments in the open docket (Case No. U-20147), it is clear that the Company was unlikely to have considered any of those comments or reply comments prior to filing testimony in the general rate case. In addition, given the nature of the open docket, there is no requirement or need for the Company (or the Commission) to consider stakeholder comments – at least not to the same degree as is necessary in a contested case process.

[3] Michigan Public Service Commission, Case No. U-20147, "In the matter, on the Commission's own motion, to open a docket for certain regulated electric utilities to file their distribution investment and maintenance plans and for other related, uncontested matters," October 24, 2023, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000AMZSnAAP.

As such, despite the Commission's stated goal of reviewing complex issues such as those related to distribution system planning and transportation electrification planning outside of general rate cases, because the proposed spending and programs can only be approved in general rate cases and because full evaluation and review can only take place in this venue, it is currently impossible to provide the same level of review, feedback, and evaluation in an open docket.

I am concerned that witness Freeman envisions a similar process for utility TEPs that may require significant stakeholder time but, ultimately, will not result in full review and evaluation until the spending is proposed in a general rate case. Although I support and have participated in the Company's TEP workshops – and appreciate changes made by the Company as a result of stakeholder feedback – fundamentally, there is no way to separate the TEPs from the general rate case process given that the spending must be approved in a rate case.

Q. Is there any way to improve the evaluation of utility TEPs short of re-integrating them with rate cases?

A. Without a statutory change, although spending associated with a TEP must be approved in a general rate case, the Commission could improve the TEP review process by requiring them to be evaluated within a contested case process rather than a comment docket. The Commission's review of utility voluntary green pricing programs under Section 61 of

Public Act 342 of 2016 has similarly evolved into a contested case process with respect to DTE and Consumers Energy Company.

Q. How does witness Freeman react to the Company's proposed EV budget?

A. According to witness Freeman,

> Staff appreciates the Company's ambition and its commitment to an EV future. However, Staff advocates for a more cautious approach with rate payers' dollars at this juncture. As Company witness Bennett noted in her testimony, EVs are still relatively new and evolving. While EV adoption continues to increase, the pace has slowed. The Company can still achieve many of its EV goals, while adopting a more cautious approach to program spending.[4]

Q. Do you concur with this reaction?

A. No. Witness Freeman offers no evidence or citations to prove his claim that the pace of EV adoption has slowed. It is unclear if this assertion is based on specific data or simply witness Freeman's feeling based on recent news reports. However, according to Bloomberg Green, six of the ten biggest EV makers in the U.S. saw much higher sales in the first quarter of 2024 than in the first quarter of 2023.[5] In fact, sales were up by 56% for Hyundai-Kia and 86% for Ford Motor Company.[6] In the second quarter of 2024, Ford sales were up

[4] Freeman Direct, pp. 7-8.

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

[6] *Ibid.*

61% over second quarter sales for 2023.[7] It is true that early in 2024, a lack of new models and delays in new vehicles have slowed the pace of increasing sales for some companies, including Tesla and General Motors ("GM"). However, GM appears to be poised to lead and drive EV growth in the U.S. for the rest of the year given improvements in its new line of batteries.[8] In fact, in the second quarter of 2024, GM sales were up 40% over the second quarter of 2023 and 34% over the first quarter of 2024.[9]

According to a July 26, 2024 report from J.D. Power, although "premium segment retail sales are down 13% -- driven by Tesla's 22% decline – the mass market segment is up 63%."[10] Despite more stringent guidance on domestic content and new model eligibility requirements, across the U.S., new EV registrations increased by more than 40% in 2023 compared to 2022.[11] Furthermore, given that leased vehicles are now eligible for federal tax credits, the rate of adoption is expected to continue increasing.[12] In Michigan, according to a report by the Alliance for Automotive Innovation, EV market penetration has reached

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

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

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

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

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

[12] *Ibid.*

4%, which is up from 3.4% in 2023 and 2.13% in 2021, indicating a marked and consistent increase in EV adoption.[13]

Long-term forecasts of EV sales also indicate strong expected future growth. With more education around EVs and EV charging, infrastructure development, and technological innovations, a recent study found that 80% of today's EV skeptics will consider the purchase of an EV in the next decade.[14] The International Energy Agency estimated in its "Global EV Outlook 2024," published in April 2024, that with stated policies in place, U.S. sales of battery electric vehicles (BEVs) are projected to increase to 2.5 million sold in 2025 (up from 1.1 million sold in 2024).[15, 16] In fact, a 2024 Environmental Defense Fund study showed that actual EV sales in 2023 outperformed 85% of expert forecasts from 2019 to 2022.[17]

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

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

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

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

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

Q. What does witness Freeman recommend related to the Business and eFleet Charger Rebates?

A. Witness Freeman arbitrarily recommends an $8 million disallowance from the proposed $16 million request for the Business and eFleet Charger Rebates program. According to witness Freeman,

> Staff is uncomfortable with this large, requested amount. It represents a significant increase from past rebate programs. Instead, Staff would like to see the Company implement a scaled down rebate effort. By moving at a more deliberate speed, DTE Electric would still be able to discover if its revised rebates plans accomplish their intended goals.[18]

Q. How do you respond to this proposal?

A. I disagree with Staff's proposed disallowance for a number of reasons. First, according to Company witness Pina Bennett, due to cost savings, funding previously approved by the Commission for the Business Charger Rebates program will allow the Company to continue to deploy funds for public direct current fast chargers (DCFC) in 2024 without seeking additional funding.[19] This shows that the Company has been conservative and prudent with funding already approved for this rebate program. As such, the Company's estimate of the need in this segment, which is based on its projections and modeling, should be accepted.

[18] Freeman Direct, pp. 8-9.

[19] Direct Testimony of Pina Bennett on behalf of DTE Electric Company ("Bennett Direct"), Case No. U-21534, pp. 8-9.

Second, it is absolutely critical that utility investments in public charging infrastructure continue and are expanded. Specifically, as outlined in my direct testimony,

> According to a Synapse Energy Economics study examining the revenues and costs associated with EVs between 2011 and 2021, EV drivers have contributed about $1 million more than their associated costs in each of Illinois and Virginia, $26.7 million more in Colorado, and $85.3 million more in New Jersey. In Colorado and New Jersey, 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.[20]

It is well established, as detailed in my direct testimony, that the existence of public EV charging stations encourages customers to purchase EVs,[21, 22, 23, 24] leading to at-home EV

[20] Direct Testimony of Dr. Laura S. Sherman on behalf of MEIU ("Sherman Direct"), Case No. U-21534, p. 21.

[21] 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/.

[22] 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.

[23] 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.

[24] 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.

charging and revenue to utilities from increased electricity sales.[25, 26, 27, 28, 29] As such, investments in EV charging should be expected to *lead* EV adoption. Cutting back on investments in EV charging because of an allegedly falling pace of adoption may simply be a self-fulfilling prophecy, itself contributing to a slower pace of EV adoption.

Third, the proposed expansions for the Business and eFleet Charger Programs, which Staff proposes to partially disallow, serve specifically to promote equity and access to EV charging for all Michiganders. The Company proposes to continue to offer rebates for school and transit buses through the eFleet Charger Program,[30] thereby serving school children and residents without access to or with limited access to a passenger vehicle. The Company also proposes to offer rebates through the Business Charger Program to on-route DCFC in disadvantaged communities ("DACs") and rural areas, as well as rebates for

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

[26] 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.

[27] 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.

[28] 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.

[29] 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.

[30] Bennett Direct, p. 48.

multi-unit dwellings, with higher rebates for properties serving low-income residents.[31] It seems wholly counter to the stated goals of the Company as well as the state to disallow funding to programs specifically designed to expand access to EVs in low-income and DACs.

Fourth, witness Freeman does not give adequate evidence or justification for the proposed $8 million disallowance beyond a statement that the pace of EV sales has slowed. As described above, there is significant evidence to refute this statement, at least over the longer-term time period of these proposed investments.

Finally, in the context of other approved utility programs to support business/fleet charging, the Company's proposed program is very small. For example, New York State has an $885 million make-ready program approved for transportation electrification,[32] the Massachusetts Department of Public Utilities recently approved nearly $400 million in statewide transportation electrification investments,[33] and Commonwealth Edison ("ComEd") anticipates spending $231 million from 2023 to 2025 on EV programs and other Illinois Commerce Commission-approved beneficial electrification measures.[34]

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

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

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

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

III. REBUTTAL OF WITNESS REVERE

Q. What does Staff witness Nicholas M. Revere propose with respect to benefit-cost analyses ("BCA") for fleet projects?

A. Specifically for non-public fleet charging rebates, witness Revere recommends that the Company conduct BCAs on an individual customer basis.[35]

Q. Do you agree with witness Revere?

A. I do agree with witness Revere that for programs such as the residential rebate programs, "it makes sense to view the benefits and costs as a whole rather than at an individual customer basis . . ."[36] However, I do not believe that the Company could conduct an individual customer-level BCA for any given fleet customer and gain an accurate representation of the full costs and benefits from electrification of that fleet. As detailed in my direct testimony, there are societal benefits of transportation electrification that cannot be considered on a project-by-project basis. In addition, there may be benefits such as distribution upgrade costs incurred by one fleet electrification project that will then lower costs for future projects. As such, I am concerned that it would be unreasonable to conduct a project-by-project BCA for fleet electrification projects.

[35] Direct Testimony of Nicholas M. Revere on behalf of Michigan Public Service Commission Staff ("Revere Direct"), Case No. U-21534.

[36] *Id.*, p. 8.

IV. REBUTTAL OF WITNESS COPPOLA

Q. What does Attorney General witness Sebastian Coppola suggest regarding EVs?

A. In a discussion of the Company's forecasted utility make-ready capital expenditures, witness Coppola indicates that

> During the first six months of 2024, EV manufacturers have realized that electric vehicles are not selling at the pace anticipated as late as 2023 and EVs are stockpiling at dealers' lots. EV buyers often have been dissatisfied with the actual driving range, particularly during the winter and hot days that quickly drain the car batteries. Reliability of certain vehicles with recalls for software and equipment failures has also created customer dissatisfaction and increased concerns and fear with prospective EV buyers. EV manufactures have cut back production of EVs, delayed new models, deferred building new batteries plants, and redirected resources to hybrid vehicles with batteries that self-charge during gasoline-fueled operation.[37]

Witness Coppola goes on to suggest that this "environment," does not support the Company's forecasted spending increase in utility make-ready capital expenditures and recommends that the forecasted capital expenditures for utility make-ready investments be reduced by 45% for 2024 and 2025.[38]

Q. What evidence does witness Coppola cite to support these claims?

A. In his direct testimony, in footnote 16, witness Coppola states that the above information was "gathered from recent articles in the Wall Street Journal, the Detroit News, and other publications."[39] According to a discovery response in this case (Exhibit MEIU-32 (LSS-

[37] Direct Testimony of Sebastian Coppola on behalf of Attorney General Dana Nessel ("Coppola Direct"), Case No. U-21534, p. 25.

[38] *Id.*, p. 55.

[39] *Id.*, p. 25.

22), witness Coppola was referring to three articles from the Wall Street Journal, three articles from The Detroit News, and a story from National Public Radio from February 2024.

Q. Is this evidence sufficient to support witness Coppola's recommendations to reduce capital expenditures on utility EV charging programs?

A. In a word, no. It is expected for a new technology that adoption will occur in fits and starts, and even traditional automotive sales experience dips. The evidence cited by witness Coppola represents a limited sample set collected during an extremely brief period of time—less than six months. This is far from sufficient to establish any kind of trend. As detailed above, EV sales continue to be strong and long-term forecasts continue to project increasing EV sales and adoption. In addition, it is well established that access to public charging is critical to ensuring both EV adoption and long-term benefits to ratepayers. Responding to a momentary blip by skimping on investment in public charging will likely threaten to reduce the rate of EV adoption and potential future charging revenues, costing ratepayers more money in the long term.

Q. What do you recommend to the Commission?

A. I recommend that the Commission ignore the vague and insufficient evidence provided by Staff witness Freeman and Attorney General witness Coppola used to suggest that investments in EV public charging are not prudent. Instead, I recommend that the Company's proposed funding for its EV programs be approved and expanded as detailed in my direct testimony.

Q. Does that complete your rebuttal testimony?

A. Yes.

4888-8029-1544, v. 6

MR. OOMS: Thank you, your Honor. Furthermore, on behalf, once again, of MEIU, I would move for the binding in of the Direct Testimony of Justin R. Barnes, which consists of a cover page, a table of contents, and 29 pages of questions and answers. He did not file rebuttal testimony, but he did sponsor Exhibits MEIU-22 through MEIU-31 with his direct testimony. I would move for the admission of those exhibits at this time as well.

JUDGE WALLACE: Is there any objection to binding in the direct testimony of Mr. Barnes?

Hearing none, the testimony is bound in.

Is there any objection to the admission of Exhibits MEIU-22 through MEIU-31?

Hearing none, those exhibits are admitted.

(Testimony bound in.)

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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

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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

[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]

[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.

[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

[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

[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]

[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 facts:

- 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]

[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:

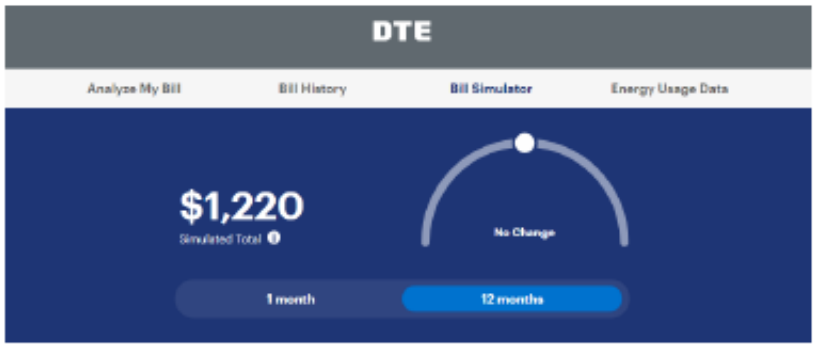
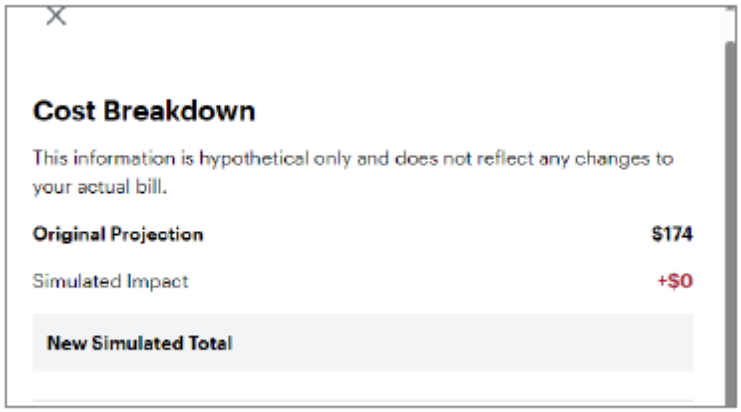


Figure 2: Monthly Bill Simulation Results Screenshot

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.

MR. OOMS: Thank you, your Honor. And finally on behalf of MEIU, we have one hearing room exhibit which consists of certain discovery responses of DTE Electric Company which we are seeking admission of in lieu of cross of certain Company witnesses. Would you like me to describe each of the discovery responses as part of this motion to admit that additional exhibit, which is MEIU-33.

JUDGE WALLACE: Lori, do you need that information, or is this sufficient?

COURT REPORTER: As long as you guys are happy with just combined discovery responses as the description, you will know what they are apparently.

MR. OOMS: I will just say that they are all of the Company's responses to MEIU's Fourth Set of Discovery Requests, so they run from MEIUDE-4.1a through MEIUDE-4.6b.

JUDGE WALLACE: All right. Is there any objection to the admission of Exhibit MEIU-33?

Hearing none, the exhibit is admitted.

MR. OOMS: Thank you, your Honor. At this time and in accordance with the stipulation of the parties, on behalf of Energy Michigan, I would move for the binding in of the Direct Testimony of Mr. Alexander J. Zakem. His direct testimony consists of a cover page

and 23 pages of questions and answers. He also filed rebuttal testimony, which consists of a cover page and, again, 23 pages of questions and answers. I would also move for the admission of the exhibits that he sponsored, Exhibits EM-1 through EM-6.

JUDGE WALLACE: Is there any objection to binding in the direct and rebuttal testimony of Mr. Zakem?

Hearing none, the testimony is bound in.

Is there any objection to the admission of Exhibits EM-1 through EM-6?

Hearing none, those exhibits are admitted.

(Testimony bound in.)

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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	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

DIRECT TESTIMONY & EXHIBITS

OF

ALEXANDER J. ZAKEM

ON BEHALF OF

ENERGY MICHIGAN

Q. Please state your name and business address.

A. My name is Alexander J. Zakem, and my business address is 46180 Concord, Plymouth, Michigan 48170.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Energy Michigan.

Q. Please state your professional experience.

A. Since January of 2004, I have been an independent consultant providing services to various clients, including Energy Michigan and its members.

From March 2002 to December 2003, I was Vice President of Operations for Quest Energy, an alternative energy supplier in Michigan. My responsibilities included the overall direction and management of Quest's power supply to its retail customers. This included power supply planning, development of customized products, negotiation with suppliers, planning and acquiring transmission rights, and scheduling and delivery of power. It also included managing risk with respect to market price movements and variation of customer loads.

Prior to joining Quest, I was employed by Detroit Edison from 1977 to 2001, where from 1998 to 2001 I was the Director of Power Sourcing and Reliability, responsible for purchases and sales of power for mid-term and long-term periods, planning for generation

capacity and purchase power needs, strategy for and acquisition of transmission rights, and related support for regulatory proceedings.

Additional experience, qualifications, and publications are provided in Exhibit EM-1 (AJZ-1).

Q. Have you testified as an expert witness in prior proceedings?

A. Yes. I have testified as an expert witness in many proceedings before the Michigan Public Service Commission ("Commission") on topics such as standby rates, retail rates and regulations, recovery and allocation of costs and revenues, and the effects of rate restructuring. I have also testified before the Federal Energy Regulatory Commission ("FERC"). Case citations are provided in Exhibit EM-1 (AJZ-1). In addition, I have participated in various Commission-sponsored workshops and stakeholder working groups.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

- Exhibit EM-1 (AJZ-1): Qualifications
- Exhibit EM-2 (AJZ-2): Fuel Subtraction
- Exhibit EM-3 (AJZ-3): Other Energy Subtraction
- Exhibit EM-4 (AJZ-4): Fuel from 2024 PSCR Plan -- U-21425 Exh A-3
- Exhibit EM-5 (AJZ-5): Other Energy in Projected Fuel
- Exhibit EM-6 (AJZ-6): Adjustments to SRM

Q. What is the purpose of your testimony?

A. On behalf of Energy Michigan, I am addressing DTE's proposed State Reliability Mechanism ("SRM") Capacity Charge regarding two aspects:

1. The first is DTE's inclusion of non-fuel expenses erroneously categorized as fuel in setting the SRM Capacity Charge.

2. The second is the conflict between the SRM statute (MCL 460.6w) and the "Cost-of-Service" statute (MC 460.11(1)).

Q. Would you summarize your conclusions and your recommendations to the Commission?

A. First, in the calculation of the SRM capacity charge, DTE has included $260,787 (000) of imputed cost of energy from certain purchased power contracts by (a) labeling such costs as "fuel related" and then (b) using the costs as if they were actually fuel as specified in the SRM statute. These costs are not fuel, and so $260,787 (000) should be eliminated from the SRM calculation.

Second, in practical determination and operation, the SRM statute, MCL 460.6w, conflicts with the Cost-of-Service statute, MCL 460.11(1). The assumptions behind the SRM statute are obsolete and flawed, and in addition the Midcontinent Independent System Operator ("MISO") has, subsequent to the enactment of the SRM statute, changed its rules governing

resource adequacy and capacity obligations to seasonal rather than annual specifications, which may render the process specified in the SRM statute further obsolete and in conflict with the Cost-of-Service statute. Therefore, I recommend that the Commission determine the SRM capacity charge using actual costs of satisfying MISO's resource adequacy obligation, in a way explained later in my testimony.

I am not a lawyer, and Energy Michigan will address the legal issues involved in determining the SRM Capacity Charge while at the same time adhering to the Cost-of-Service statute in its brief. As an expert in the field of electric regulation, I can advise the Commission on the operational meaning of the plain words in the statutes and the implications of the new MISO rules.

I. Eliminate "Fuel-Related" Costs That Are Not Fuel.

I-A. SRM subtracts non-capacity costs and considers "offsets."

Q. How does the SRM statute specify the determination of the SRM Capacity Charge?

Section 6w of Public Act 341 of 2016 describes how the charge should be calculated and lists the factors to include or consider. The statute assigns to the Commission the responsibility to implement various aspects of the SRM statute.

The statute specifies defined subtractions of non-capacity costs in determining capacity costs that are to be included in the SRM Capacity Charge calculation, as follows:

> The commission shall do both of the following [. . .]:
>
> (a) For the applicable term of the capacity charge, include the capacity-related generation costs included in the utility's base rates, surcharges, and power supply cost recovery factors, regardless of whether those costs result from utility ownership of the capacity resources or the purchase or lease of the capacity resource from a third party.
>
> (b) For the applicable term of the capacity charge, subtract all non-capacity-related electric generation costs, including, but not limited to, costs previously set for recovery through net stranded cost recovery and securitization ***and*** the projected revenues, net of projected fuel costs, from all of the following:
>
> (i) all energy market sales.
> (ii) off-system energy sales.
> (iii) ancillary services sales.
> (iv) energy sales under unit-specific bilateral contracts.[1]

The projected revenues net of projected fuel costs listed in the SRM statute in (b) above are commonly referred to as "offsets" in discussions of SRM determinations.

Q. In its determination of the SRM Capacity Charge, has DTE included its capacity-related generation costs?

A. Yes. DTE's Exhibit A-16, Schedule F1.5, page 1 of 6 ("the SRM Exhibit") shows the calculation of the SRM Capacity Charge.[2] It begins with "Net Production Costs Rev. Req. on line 1, $3,213,177 (000), which comes from the Production cost of service study.

Q. Has DTE subtracted all non-capacity-related electric generation costs?

[1] MCL 460.6w(3)(a)&(b) (emphasis added).

[2] Exhibit A-16, Schedule F1.1, page 1 of 4, line 31, column (a). All citations to Exhibit A-16, Schedule F1.5 are to the revised version that DTE issued.

A. On the SRM Exhibit, non-capacity costs on lines 2, 3, 4, 5, and 6 are subtracted from Net Production Costs on line 1, resulting in a Subtotal of $1,957,094 (000) on line 7. The Subtotal represents capacity-related generation costs after the removal on non-capacity portions. I am not questioning the validity of these numbers, yet I will address the values and sources on two of the lines which are relevant to the exclusion of non-fuel values later in the calculation of energy market sales "offsets" required by the SRM statute.

I-B. DTE has correctly subtracted fuel from Production Costs

Q. Please explain the two values you are addressing.

A. The first value is line 2 on the SRM Exhibit, labeled "Less Fuel," with a value of $914,888 (000). This value comes from the Production cost of service study in this proceeding, the same exhibit that is the source of Net Production Costs Rev. Req. on line 2. I have prepared Exhibit EM-2 (AJZ-2) to provide an easy reference to the connection of fuel in the cost of service study and fuel in the SRM Exhibit. The "Less Fuel" label denotes a non-capacity cost that DTE subtracts from Production costs in the first part of the SRM Exhibit.

The second value is line 5 in the SRM Exhibit, labeled "Less Other Energy in PP," with a value of $260,787 (000). By subtracting this value from Production costs, DTE denotes it is a non-capacity cost, and so removes it from Production costs in the first part of the SRM Exhibit.

I-C. "Less Other Energy in PP" is not Fuel

Q. What is the source of the $260,787 (000) labeled "Less Other Energy in PP?

A. The value $260,787 on line 5 of the SRM Exhibit is the sum of two values: $2,925 from Exhibit A-26, Schedule P1, and $257,862 from Exhibit A-26, Schedule P2. I have prepared Exhibit EM-3 (AJZ-3) to provide an easy reference to how the sum of the two values connects to "Less Other Energy in PP" on the SRM Exhibit.

Q. How does DTE determine the two values that sum to $260,787?

A. On Exhibit A-26, Schedule P1, the value $2,925 appears in column (f) labeled "Total Fuel-Related Generation Cost," which footnote 1 on Schedule P1 identifies as:

> "Note 1: Fuel-Related Generation Cost based on difference of total projected PURPA PSCR Cost and the Capacity Related Generation Cost."

On Exhibit A-26, Schedule P2, the value $257,862 appears in column (j) labeled "Total Fuel-Related Generation Cost," which footnote 1 on Schedule P2 identifies as:

> "Note 1: Fuel-Related Generation Cost based on difference of total projected PA295 PSCR Cost and the Capacity Related Generation Cost."

The total of $2,925 plus $257,862 is $260,7872, which appears on line 5 of the SRM Exhibit.

Q. Does the caption "Total Fuel-Related Generation Cost" mean that $2,925 and $257,862 are in fact fuel costs?

A. No, not at all. These two numbers are simply the total costs of the PPA contracts that remain after backing out the portion of the total cost that DTE attributes to paying for capacity rights delivered under the contracts. DTE has identified such exactly in the footnotes on Schedules P1 and P2, cited above. The costs of $2,925 and $257,862 -- which total $260,787 -- are correctly non-capacity costs, but they are not actual fuel costs. [DTE has not demonstrated in its testimony that all non-capacity costs are, in fact, fuel costs.]

I-D. DTE erroneously includes $260,787 as fuel in the offset calculation.

Q. How does DTE determine the energy sales "offsets" as prescribed in the SRM statute?

A. DTE projects revenues for two categories of "offsets" -- Energy Market Sales and Regulation, Spinning, and Supplemental Ancillary Services Sales. These are shown on Exhibit A-26, Schedule P3, and total $2,184,379 (000) appearing on line 16. In direct testimony, DTE states that these projected revenues for year 2025 are taken from DTE's 2024 PSCR Plan (U-21425).

> The wholesale energy revenue forecasted for all Company assets (including PPAs) in the Company's 2024 PSCR Plan (U-21425) was calculated to be $2.180 billion shown on Exhibit A-26, Schedule P3, line 11.[3]

> The Company's 2024 PSCR Plan projected that Company's generation resources would generate $4.3 million of wholesale revenue associated with regulation, spinning, and supplemental reserves. The projected wholesale ancillary services revenues from the Company's generation resources in 2025 are shown on Exhibit A-26, Schedule P3, line 14.[4]

[3] Direct Testimony of Mr. S. D. Burgdorf, page 9, lines 7-10.

[4] Mr. Burgdorf, direct testimony, page 9, line 21 to page 10, line 1.

The total projected wholesale energy sales revenue including ancillary services in 2025 is $2.184 billion as shown on Exhibit A-26, Schedule P3, line 15. [5]

Q. What number does DTE use for "net of projected fuel costs" prescribed in the SRM statute?

A. DTE uses a fuel cost of $940,245 from its 2024 PSCR plan, and adds to it the $260,787 value of $260,787 that appears on line 5 of the SRM Exhibit in this proceeding, as discussed previously. The total of $940,245 plus $260,787 equals $1,201,032, and this total appears on lines 20 and 21 of Exhibit A-26, Schedule P3.

Exhibit EM-4 (AJZ-4) -- a copy of an exhibit from DTE's 2024 PSCR Plan, Case No. U-21425 -- shows the source of the $940,245 fuel value. I have prepared Exhibit EM-5 (AJZ-5) to provide an easy reference to how the sum of the two values -- $1,201,032 -- connects to line 20 and 21 on Schedule P3.

Q. How does DTE characterize the $1,201,032 number?

A. On Exhibit A-26, Schedule P3, line 20, DTE labels $1,201,032 as "Fuel," and on line 21 labels it as "Total Projected 2025 Fuel Generation Expense."

Q. Is the $1,201,032" projected "Fuel" expense entirely fuel?

[5] Mr. Burgdorf, direct testimony, page 10, lines 7-8. Note that the $2.184 billion number is on line 16 of the cited exhibit, rather than line 15.

A. No. From the evidence in DTE's testimony and exhibits, explained above, $940,425 represents the actual fuel portion of $1,201,032, and the remaining $260,787 represents the difference between total costs and capacity costs for specified power purchase agreements, as DTE notes on Exhibit A-26, Schedules P1 and P2, explained previously.

Q. How does DTE use the $1,201,032 projected "Fuel" expense in the calculation of the SRM Capacity Charge?

A. As cited previously, the SRM statute requires that capacity costs be offset by "projected revenues" (for four categories of sales) "net of projected fuel costs." On Exhibit A-26, Schedule P3, DTE shows the projections and the netting as follows:

Line	Label	Value
16	"Total Projected 2025 Energy Sales Revenue"	$2,184,379
21	"Total Projected 2025 Fuel Generation Expense"	$1,201,032
23	"Projected 2025 Energy Sales Revenue Net of Fuel Costs"	$983,347

The net of $983,347 is transferred to the SRM Exhibit A-16, Schedule F1.5, page 1 of 6, and becomes the offset shown on line 9 of that exhibit.

Q. Should the $260,787 be included in the offset calculation?

A. No. That expense may be a valid non-capacity expense to be subtracted on line 5 of the SRM exhibit, but it is not fuel. The description of the $260,787 expense evolves from a

non-capacity expense into imputed fuel in the course of DTE's exhibits, on the way to the calculation of the SRM Capacity Charge, as follows:

a. Difference between total projected PPA cost and Capacity Related Cost.
(Exh A-26, Sched P1 and P2, footnotes.)

b. "Fuel-Related Generation Cost"
(Exh A-26, Sched P1 and P2, column titles.0

c. Included in "Fuel"
(Exh A-26, Sched P3, line 20.)

d. Included in "Total Projected 2025 Fuel Generation Expense."
(Exh A-26, Sched P3, line 23.)

e. Included in the netting of fuel out of the projected sales revenue.
(SRM Exhibit, Exh A-16, Sched F1.5, page 1 of 6, line 9.)

The plain language of the SRM statute states "net of projected fuel costs." It does not say "net of projected imputed fuel costs," or "net of projected PPA costs less capacity costs," or "net of all variable costs," or "net of projected fuel-related costs," or "net of all costs required to make the sale," or any other netted cost except fuel. The SRM statutory language is clear. The SRM statute was a negotiated outcome, not a clean financial and operational solution to a defined problem, and there are flaws, which I will address later in my testimony. DTE may object to the reasonableness of the SRM statute, but this case U-21534 is not the forum to negotiate a change to MCL 460.6w(3), the SRM statute.

Q. Has the Commission approved the specific inclusion of imputed fuel costs of PPA in past determinations of the SRM Capacity Charge?

A. I have looked but cannot find any evidence that the Commission in the past has specifically addressed the imputed fuel costs in PPAs as part of "net of projected fuel" in determining offsets. The Commission has addressed other proposed inclusions in "net of projected fuel", such as emission and chemicals expense, and has removed such expenses from the SRM calculation in previous orders. An error that comes to light in this proceeding should be fixed here, whether or not it was present but unaddressed in past Commission proceedings.

I-E. The SRM Capacity Charge should be revised.

Q. How should the determination of the SRM Capacity Charge be revised if $260,787 of non-fuel cost is removed from the netting of fuel in the offsets to the SRM capacity cost?

A. I have prepared Exhibit EM-6 to show the adjustments to eliminate $260,787 from the projected fuel costs. Eliminating the $260,787 from fuel costs in the offset determination results in the offset on line 9 of the SRM Exhibit (A-16, Sched F1.5, page 1 of 6) changing from $983,747 to $1,243,954. The outcome is that DTE's proposed SRM Capacity Charge of $217.30 per MW-day would be changed to $159.21 per MW-day on line 17 of the SRM Exhibit.

If the Commission's final order in this proceeding results in changes to other values proposed by DTE -- such as a revision to Net Production Cost Revenue Requirement -- then those changes should be reflected in the SRM calculation also. In the absence of such

additional changes, I recommend that the Commission set DTE's SRM Capacity Charge at $159.21 per MW-day.

II. Follow the "Cost of Service" Statutory Requirements to Determine the SRM Capacity Charge.

Q. Is the determination of the SRM Capacity Charge affected by the Cost-of-Service statute, MCL 460.11(1)?

A. Yes. The SRM statute MCL 460.6w is not the only guide for the Commission in determining a just and reasonable SRM Capacity Charge. MCL 460.11(1), enacted in PA 286 in 2008, ("Cost-of-Service statute") which requires the Commission to set "electric rates equal to the cost of providing service to each customer class"[6] is also relevant. To the extent that application of Section 6w and Section 11(1) produce different results, the Commission has to decide how to reconcile competing statutory demands so as to determine and apply a SRM Capacity Charge that it is also in accordance with the Cost-of-

[6] MCL 460.11(1) "Except as otherwise provided in this subsection, the commission shall ensure the establishment of electric rates equal to the cost of providing service to each customer class. In establishing cost of service rates, the commission shall ensure that each class, or sub-class, is assessed for its fair and equitable use of the electric grid. If the commission determines that the impact of imposing cost of service rates on customers of an electric utility would have a material impact on customer rates, the commission may approve an order that implements those rates over a suitable number of years. The commission shall ensure that the cost of providing service to each customer class is based on the allocation of production-related costs based on using the 75-0-25 method of cost allocation and transmission costs based on using the 100% demand method of cost allocation. The commission may modify this method if it determines that this method of cost allocation does not ensure that rates are equal to the cost of service." *[Emphasis added.]*

Service statute, so that customers are assessed a just and reasonable rate for fair and equitable use of the electric grid.

The Commission has implemented the SRM Capacity Charge in several previous proceedings. However, since the enactment of the SRM statute, the Midcontinent Independent System Operator ("MISO") has changed its rules governing resource adequacy and capacity obligations, which may render the previous Section 6w process obsolete and in conflict with the Cost-of-Service statute.

Q. What should the Commission consider regarding the SRM Capacity Charge?

A. Since MISO capacity requirements and costs are now determined by season – four seasons with differing quantities and costs – the Commission could require that the SRM Capacity Charge also be determined by season, to reflect accurately the operational parameters in the Section 6w statute and to comply with the Cost-of-Service statute.

II-A. Meeting the capacity obligation to MISO.

Q. How does MISO quantify the capacity obligation for a Load Serving Entity ("LSE")?

A. The MISO tariff states how the capacity obligation, called the Planning Reserve Margin Requirement ("PRMR") for every Load Serving Entity ("LSE") in a retail choice area is to be determined. An LSE could be the local utility such as DTE Electric or an Alternative Energy Supplier ("AES").

If a customer has not been assigned to any LSE -- for example, a new customer to the service area -- the "provider of last resort" under the MISO tariff (here, DTE) will be assigned the responsibility to satisfy the capacity obligation attributed to that customer.[7]

Q. How does MISO impose the capacity obligation on LSEs?

A. MISO imposes the capacity obligation on LSEs by charging LSEs the MISO Auction Clearing Price ("ACP") (in dollars) multiplied by the PRMR (in MW) of the LSE.

Q. How does an LSE satisfy its capacity obligation to MISO?

A. MISO charges each LSE for necessary capacity using an amount based on its PRMR (MWs) multiplied by the ACP (dollars), and likewise pays owners of financial rights to capacity assets (known as Zonal Resource Credits or "ZRCs") the same ACP per MW. Consequently, an LSE satisfies its capacity obligation to MISO with payment of money.

II-B. MISO seasonal process affects the SRM Capacity Charge.

Q. What is the MISO seasonal resource adequacy process?

A. After about two years of development, MISO began a process on June 1, 2023, to plan for resource adequacy on a four-season basis, as opposed to the previous annual basis. Virtually every relevant factor – such as load forecasts, Planning Reserve Margin %, PRMR, Local Clearing Requirements, Auction Clearing Prices, accredited capacity values

[7] MISO Module E-1, section 69A.1.1.1.a.

of resources, etc. – are now evaluated and expressed by four seasonal values, not by one annual value. For example, the ACPs for Michigan Zone 7 for summer, fall, winter, and spring of the 2024-2025 Planning Year are $30, $15, $0.75, and $34.10 per MW-day, respectively.[8] These numbers can be compared to DTE's proposed single annual SRM Capacity Charge of $217.30 per MW-day as shown in DTE's SRM Exhibit A-16, Schedule F1.5, page 1 of 6, line 17.

Q. What is the effect of MISO's Seasonal Process on the SRM Capacity Charge?

A. MCL 460.6w(6) states:

> (6) A capacity charge shall not be assessed for any portion of capacity obligations for each planning year for which an alternative electric supplier can demonstrate that it can meet its capacity obligations through owned or contractual rights to any resource that the appropriate independent system operator allows to meet the capacity obligation of the electric provider. The preceding sentence shall not be applied in any way that conflicts with a federal resource adequacy tariff, when applicable. *[Emphasis added.]*

While Energy Michigan will address the legal implications of this section of the statute in its brief, the operational plain meaning is that MISO now allows an LSE to meet its capacity obligation by season, capacity resources (ZRCs) are qualified by season, the payments to MISO for PRMR are by season, the payments by MISO to holders of Zonal Resource Credits are by season. Therefore, the SRM Capacity Charge should be applied by season, not for all seasons in a year via one annual SRM Capacity Charge.

[8] https://cdn.misoenergy.org/2024%20PRA%20Results%20Posting%2020240425632665.pdf. See page 2.

Q. What is the cost of satisfying MISO's seasonal capacity requirement?

A. The cost to an LSE of satisfying MISO's seasonal capacity requirement can be determined exactly: it is

- the LSE's PRMR (in MW)
- times the MISO Seasonal Auction Clearing Price (in $ per MW-day)
- times the number of days in the season.

For example, using current prices, if the LSE's obligation were 1 MW for the summer season (June-August), and the summer Auction Clearing Price were $30 per MW-day, then the cost -- MISO's charge to the LSE -- would be:

1 MW x $30 per MW-day x 92 days = $2,760.

Q. If an LSE is capacity deficient for 1 MW under the Commission's demonstration process, and the local utility has to satisfy such deficiency to MISO under Section 6w, what is the cost to the utility?

A. In the example above, if the utility were to pay the MISO bill, then the utility would pay MISO $2,760.

Q. Could the utility use its extra capacity, if any, to satisfy the LSE's deficiency, and if so, what would be the cost?

A. Under the present MISO tariff, the utility could not "use" extra capacity, but rather would offset the payment from MISO for that extra capacity. Prior to 2013, LSEs had to provide

MISO with owned or contracted capacity to satisfy their capacity obligations. Since the beginning of the MISO annual capacity Auction in 2013, LSEs simply pay the money. If an LSE owns qualified capacity in the form of Zonal Resource Credits, then MISO will pay the LSE the same Auction Clearing Price for the capacity credits as it charges the LSE for its PRMR.

Therefore, since under the MISO tariff all Zonal Resource Credits must be offered into the Auction, the utility would pay MISO the $2,760 to satisfy the LSE's capacity obligation. This payment would in effect offset the $2,760 it would receive for 1 MW of Zonal Resource Credits. Thus, the cost to the utility of providing the service of satisfying the deficient LSE's capacity obligation to MISO with "extra capacity" is still exactly $2,760, either way.

II-C. Determine the SRM Capacity Charge by season and set equal to the MISO seasonal Auction Clearing Price.

Q. Could an SRM Capacity Charge that is calculated annually be applied to a seasonal capacity deficiency?

A. An annual SRM Capacity Charge could not be applied and still match the cost of service, since the cost of service is determined by season. By simple arithmetic, it is true that if the utility were to calculate four seasonal SRM Capacity Charges from the same data used for the annual SRM Capacity Charge, then the average of those four seasonal charges (weighted by days in the season) would equal the annual charge, but the application of the

annual charge would equal the cost of four seasonal charges only if the LSE were deficient for all four of the seasons, which may be unlikely considering the Commission is requiring demonstration by season.

Q. If the annual SRM Capacity Charge proposed by DTE were implemented, what would the outcome be?

A. In the previous example for 1 MW of the summer season, where the MISO charge is $2,760, the outcome of the SRM Capacity Charge proposed by DTE would be:

1 MW x $217.30 per MW-day x 92 days = $19,991.60.

As a result, an LSE/customer paying this charge of $19,991.60 would not be paying the straightforward actual cost of the service it receives -- the service of satisfying a 1 MW capacity deficiency in capacity obligations to MISO -- which cost to the utility is exactly $2,760.

Q. How do you recommend the SRM Capacity Charge be determined such that it complies with the Cost-of-Service statute?

A. A workable and fair solution would be to set the SRM Capacity Charge at the MISO seasonal Auction Clearing Price and apply that charge to the MW value of the deficiency, for the days of the season that an LSE is deficient. This would comport exactly with the cost of providing the service -- the service of satisfying the MISO capacity obligation -- that the LSE/customer receives. This option is exactly consistent with the plain words of the Cost-of-Service statute.

Q. Would setting the SRM Capacity Charge at the MISO seasonal Auction price harm full-service customers?

A. Absolutely not. DTE would collect the exact cost of the service it provides to the LSE/customer. DTE would end up in the exact same financial position whether (a) it satisfied the LSE/Customer's capacity obligation to MISO and collected the defined SRM Capacity Charge or (b) did not satisfy the LSE/Customer's capacity obligation to MISO and did not collect the defined SRM Capacity Charge. Either way, full-service customers would not be harmed or even affected.

Q. Would setting the SRM Capacity Charge at the MISO seasonal Auction price be consistent with Section 6w?

A. Energy Michigan will address this further in its brief. Setting the SRM Capacity Charge at the MISO seasonal Auction price is obviously consistent with the Cost-of-Service statute. The plain wording of Section 6w does not appear to have envisioned anything other than an annual charge. Thus Section 6w may be impossible to follow on a seasonal basis in the same way the Commission interpreted it on an annual basis, and the Commission may have to use reasonable judgement in applying Section 6w in a way that harmonizes Section 6w with the Cost-of-Service statute and MISO's new process.

Q. Would setting the SRM Capacity Charge at the MISO seasonal Auction price create a subsidy to DTE's full service customers or to an AES's electric choice customers?

A. No. DTE expresses concerns about subsidies,[9] but there are no subsidies. Both DTE and the AES must satisfy the exact same reserve margin and PRMR obligations, pay the exact same price to MISO for capacity, pay the exact same price for transmission service, and their customers pay the exact same price for distribution service. How there can be a "subsidy" under the current grid rules and procedures, DTE does not specify.

If the SRM Capacity Charge were set at the MISO seasonal Auction price, as explained above, to satisfy a capacity obligation to MISO of $2,760 (quantified in section II-B previously), an AES would pay DTE $2,760 and DTE would pay MISO the same amount $2,760. There is no subsidy.

Under the current and DTE proposed SRM determination, to satisfy a capacity obligation to MISO of $2,760, an AES would pay DTE $19,991.60 (quantified in section II-C), and DTE would pay MISO the $2,760. The difference of $17,231.60 would go to DTE full service customers. That is a subsidy.

Q. Does DTE provide electric choice customers with "temporary capacity"?

A. No. Electric Choice customers do not obtain "temporary capacity" from the local utility — that ceased on April 1, 2005, when MISO began dispatching all the generation in the region to service all the load in the region. For the last 19 years, it has not been accurate

[9] See Mr. Burgdorf, direct testimony, page 11, lines 7-19.

to think that DTE's power plants serve DTE's customers or any other specified group of customers.

Market-based solutions to resource adequacy -- rather than physically tying specific facilities to specific customers -- have existed for the last couple of decades in most all regions. Ownership of generation provides a hedge against the volatility of market prices over time, and DTE is getting compensated for using that hedge to minimize price variation for its full service customers. DTE is not subsidizing anything.

II-D. Recommendation to meet both the SRM statute and the Cost-of-Service statute.

Q. What is your recommendation to the Commission?

A. I recommend that the Commission set the SRM Capacity Charge at the MISO seasonal Auction Clearing Price and apply that charge to the MW value of an LSE's seasonal capacity deficiency, adjusted by the number of days in the season. This determination:

a. follows the Cost-of-Service statute, MCL 460.11(1),

b. keeps the local utility neutral if it has to satisfy another LSE's capacity obligations under MCL 460.6w,

c. allows the Commission to maintain its capacity demonstration requirements by season, and

d. maintains the function of Section 6w that the local utility satisfy the capacity obligation to MISO for any LSE that is deficient of capacity under the demonstration process.

The LSE/customer would pay:

-- seasonal capacity deficiency (MW of seasonal capacity deficiency per the Commission's demonstration process)

-- x MISO seasonal Auction Clearing Price ($ per MW-day)

-- x number of days in the season.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

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 rates schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	)))))))	**Case No. U-21534**

REBUTTAL TESTIMONY

OF

ALEXANDER J. ZAKEM

ON BEHALF OF

ENERGY MICHIGAN

Q. Please state your name and business address.

A. My name is Alexander J. Zakem, and my business address is 46180 Concord, Plymouth, Michigan 48170.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Energy Michigan ("Energy Michigan").

Q. Are you the same Alexander J. Zakem who provided direct testimony in this proceeding?

A. Yes, I am.

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

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address two proposals of the Michigan Public Service Commission Staff ("Staff") regarding the method of determining the State Reliability Mechanism ("SRM") Capacity Charge:

I. True-Up -- The first Staff proposal is to include in the new SRM Capacity Charge a reconciliation or "true-up" of projected values that were used in the calculation of the current SRM Capacity Charge.

I will explain why the current true-up method does not work, and as a result, the Staff's proposed true-up of $168.1 million in the calculation of the SRM capacity charge should be eliminated.

II. CONE -- The second Staff proposal was to use the Cost of New Entry ("CONE") as the new SRM Capacity Charge.

The CONE concept has merit, depending on the context. However, under the present resource adequacy processes of the Midwest ISO ("MISO"), the CONE concept may no longer be workable, and revisions may be required.

I. True-Up

Q. What does the statute governing the SRM say about "truing up" projected quantities that are in the calculation of the SRM Capacity Charge?

A. While I am not a lawyer, and Energy Michigan will address legal aspects in its brief, I can explain the plain operational words and implications of the SRM statute. The SRM was enacted in PA 341 of 2016, MCL 460.6(w) ("SRM statute"). Regarding a true up, the statute states:

> The commission shall provide for a true-up mechanism that results in a utility charge or credit for the difference between the projected net revenues described in subsection (3) and the actual net revenues reflected in the capacity charge. The true-up shall be reflected in the capacity charge in the subsequent year. The methodology used to set the capacity charge shall be the same methodology used in the true-up for the applicable planning year. [*MCL 460.6(w)(4). Emphasis added.*]

Q. Is this provision clear and practical enough for a fair and accurate implementation?

A. No, not at all. The SRM statute was a negotiated deal, not a cooperative problem-solving effort. As such, it has a number of flaws that are obstacles to a fair and accurate implementation.

Q. Would you explain, regarding the true-up provision?

A. The main operational flaw is that the true-up is supposed to be "reflected in the capacity charge in the subsequent year." This does not make sense if the intent is to adjust the SRM capacity charge already paid by a customer for the current year.

Q. Could you give an example?

A. Yes. A simple example illustrates the difficulty.

Suppose Customer A has been deemed to be short of demonstration capacity and consequently owes and pays the SRM capacity charge in Year 1. If the SRM capacity charge in Year 1 contains a true-up (positive or negative) for the previous year's SRM capacity charge, then Customer A gets a true-up for a charge it did not pay. This is contrary to cost-of-service principles.

Further, the SRM capacity charge in Year 1 contains a credit determined by the projected energy market sales and fuel for Year 2, the following year. In the example, assume Customer A pays the charge in Year 1.

Suppose in Year 2, it turns out that the sales and fuel projections were too low, and so Customer A is due money back, for the true-up. How does Customer A get the true-up money? There are two operational situations for Customer A in Year 2 -- Customer A either satisfies or does not satisfy its capacity demonstration in Year 2:

1. Assume Customer A satisfies its capacity demonstration in Year 2. Thus, Customer A does not pay the SRM capacity charge in Year 2. Since the true-up for Year 1 is "reflected in the capacity charge in the subsequent year" -- subsequent meaning in Year 2 -- and Customer A does not pay the capacity charge in Year 2, Customer A does not receive the true-up amount for the Year 1 charge. Straightforward.

2. Assume Customer A does not satisfy its capacity demonstration in Year 2. Thus, Customer A pays the SRM capacity charge for Year 2. Since the true-up for Year 1 is reflected in the charge for Year 2, Customer A does receive the true-up for Year 1. But at the same time, the Year 2 capacity charge includes projected sales and fuel for Year 3, and so Customer A pays for the projected amounts for Year 3 in the SRM capacity charge for Year 2. To get a true-up for projections that are included in the Year 2 SRM capacity charge, Customer A has to be subject to the SRM charge in Year 3 -- which reflects the true-up for Year 2 but also includes projected sales and fuel for Year 4. And so it continues, such that Customer A never gets the proper true-up.

Eventually, if Customer A satisfies its capacity demonstration in year N, the situation is transformed into #1 above, where Customer A is not charged the SRM capacity charge in Year N, and therefore gets no true-up for the Year N-1 SRM capacity charge that Customer A did pay.

Q. What does this example illustrate?

A. This example illustrates that under the present method of implementing a true-up, (a) the first year that a customer pays the SRM capacity charge, the charge is always in error and (b) the last year -- in a sequence of years -- that a customer pays the SRM capacity charge, the charge always is in error. Further, and consequently, if a customer pays the SRM capacity charge for only one year, then the customer is subject to both errors.

Q. Did DTE propose or include a true-up adjustment?

A. No. DTE sees no need for a true-up until a customer is charged the SRM capacity charge:

> **Q23. How does the Company intend to handle any reconciliation of previous year variance of wholesale energy sales revenue net of fuel costs?**
>
> A23. The Company currently has no electric choice customers being assessed a capacity charge, thus no reconciliation with any customers has been previously done. The Company files a reconciliation exhibit in the annual PSCR Reconciliation case that would be used for any reconciliation adjustment if a customer were to be charged the SRM.[1]

[1] Direct testimony of Mr. Shaun D. Burgdorf, page 11, line 21, to page 12, line 2.

Q. Is it possible under present implementation methods to do a fair and accurate true-up to the SRM capacity charge?

A. No. Under the plain words of the SRM statute and considering the present implementation procedures that have been set up, it is not possible to do a fair and accurate true-up to the SRM capacity charge. There are a number of obstacles:

a. ***One Year:*** The true-up does not work if a customer is assessed the SRM charge for only 1 year. There are two errors. Explained above.

b. ***Multiple Years:*** The true-up does not work if a customer is assessed the SRM charge for multiple years in a row. The first year and the last year have errors. Explained above.

c. ***Season:*** The true-up does not work under the current Midwest ISO ("MISO") resource adequacy process of setting capacity obligations by season, rather than for a year. At present, the SRM charge is for one year, not by season. Consequently, both the calculation of the SRM charge and the annual true-up do not match the capacity demonstration required by the Commission.

d. ***Not a Separate Charge:*** The true-up does not work because the SRM charge -- although it is a per MW charge -- is not assessed to a customer by MW of shortfall in capacity demonstration, even though the MW are known exactly. Rather, under present implementation procedures, the total dollars in the SRM charge are allocated to rate classes and form part of the price design in those classes. Consequently, to receive the correct true-up dollars, a customer would have to use exactly the same amount of energy at the same times at the same prices for two years in a row.

e. ***Changing Allocations:*** The true-up does not work, even if a customer had the same energy characteristics two years in a row, because the allocation factors to rate classes can change from rate case to rate case, and as a result the amount of the total SRM charge that is included as part of any one price can change from year to year. This means that dollars of true-up may not be allocated to customers in the same way that the SRM was charged.

Q. What is the Staff's proposal regarding the true-up?

A. Staff proposes that the true-up amount for the difference between (a) the sales and fuel projections that are in the present SRM capacity charge and (b) the actual sales and fuel be put into the new SRM capacity charge. As in the example above, Year 1 would be the

present charge, Year 2 would be the new charge, and the true-up for Year 1 projections would become part of the Year 2 charge. Staff's rationale is:

> Staff interprets this section [MCL 460.6w(4), quoted above] as requiring that a reconciliation be performed and included in the capacity charge calculation each year, regardless of whether a charge was administered in that year or not.[2]

In accordance with its rationale, Staff makes a true-up adjustment of $168.1 million in the calculation of the new SRM capacity charge.[3] Considering that the true-up process is always inaccurate, and until a fair and accurate implementation method is put in place, this $168.1 million adjustment should be eliminated.

Q. Is it possible for a true-up to the SRM capacity charge be implemented fairly and accurately?

A. There are three factors necessary in implementing a fair and accurate true-up. The basis for these factors is for the Commission to recognize that the cost-of-service statute, MCL 460.11(1)[4], supports charging the SRM fairly. The true-up process exists to protect both

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[2] Direct testimony of Mr. Mark J. Pung, page 8, lines 5-7.

[3] Mr. Pung, direct testimony, page 8, lines 15-21.

[4] "Except as otherwise provided in this subsection, the commission shall ensure the establishment of electric rates equal to the cost of providing service to each customer class. In establishing cost of service rates, the commission shall ensure that each class, or sub-class, is assessed for its fair and equitable use of the electric grid. If the commission determines that the impact of imposing cost of service rates on customers of an electric utility would have a material impact on customer rates, the commission may approve an order that implements those rates over a suitable number of years. The commission shall ensure that the cost of providing service to each customer class is based on the allocation of production-related costs based on using the 75-0-25 method of cost allocation and transmission costs based on using the 100% demand method of cost

customer and utility from errors in forecasting energy market revenues and fuel costs. The Commission can use the cost-of-service statute to implement the true-up process in a fair and accurate way that works for both customer and utility.

It has been almost seven years since the initial orders implementing the SRM capacity charge, six utilities presently have SRM capacity charges, and 937 customers are on Electric Choice.[5] Not one customer has paid an SRM capacity charge. The SRM true-up as presently implemented does not and cannot work. A more straightforward, cost-based approach is needed.

Going forward, starting with this proceeding, the Commission could use the following process for the true-up of the SRM capacity charge.

True up only if charged -- First, true-up to energy sales and fuel projections should be considered by the Commission if, and only if, a customer actually pays an SRM capacity charge, which so far has never happened. True-up dollars should not automatically become part of the next SRM charge calculation.

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allocation. The commission may modify this method if it determines that this method of cost allocation does not ensure that rates are equal to the cost of service." [MCL 460.11(1). Emphasis added.]

[5] "Status of Electric Competition in Michigan," Michigan Public Service Commission, February 1, 2024, page 21, Figure 2.

Apply the SRM charge the same way it is determined, by MW -- Second, the SRM capacity charge should be applied to a customer according to the MW capacity deficiency that triggered the charge, rather than included in price design in a rate. Customer MW are known.[6] For example, if a 2 MW customer is deemed short according to the capacity demonstrations, then that customer should be charged the SRM capacity charge -- which is on a per MW basis -- times 2 MW.

True up the same way the SRM charge is applied, by MW -- Third, if a customer pays the SRM capacity charge, the amount paid that is attributed to projected energy sales and fuel is known exactly, on a per MW basis. For true-up, the difference in the SRM capacity charge between the calculation using the projections and the calculation using actual energy sales and fuel is known exactly, also on a per MW basis, and that difference should be charged or paid to the customer using the same MW number for which the customer paid the SRM capacity charge.

It is important to note that a true-up adjustment could go either way -- either money owed by the utility to the customer or money owed by the customer to the utility. Neither the customer nor the utility should be harmed by, or benefit by, errors in projections of energy

[6] In retail choice areas, such as Michigan, MISO requires that each customer be assigned a peak load contribution ("PLC") in MW. The Planning Reserve Margin Requirement ("PRMR") used in the capacity demonstration process is the sum of the PLCs for all customers that a supplier serves, and so each customer is assigned its PLC in MW as part of the total MW requirement of the supplier for the capacity demonstration.

sales and fuel compared to the eventual actual outcomes. The method described above works fairly and exactly for both customer and utility.

II. Use of CONE as the SRM Capacity Charge

Q. Is the Staff presenting a different way to determine the SRM capacity charge, versus the present method of using a utility's embedded production costs?

A. Yes. The Staff is recommending that the Commission consider setting the SRM capacity charge to the cost of new entry ("CONE").[7]

Q. What is the cost of new entry, or CONE?

A. CONE is an economic term meaning the minimum cost for a new supplier to enter a market. In the electric industry, in this discussion, the term refers to the minimum cost to provide MISO with only "capacity," meaning without any additional costs that would provide some other benefits such as low priced energy or ancillary services, and without any running costs. In the electric industry, it is common to use the annual fixed costs associated with building a simple peaker, such as a combustion turbine or CT, to calculate CONE. The Midwest ISO ("MISO") uses a CT as a model for CONE, and the Staff's presentation does the same. The CT model is a reasonable estimate for CONE.

Q. What is capacity, in plain language?

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[7] Direct testimony of Mr. Nicholas M. Revere, page 8, line 21 to page 12, line 19.

A. Capacity is the *rate* at which energy can be converted from one form to another, ending with electricity, such as from coal to heat to mechanical energy to electricity. The rate at which energy is converted is called *power*, and electric power is expressed in Watts. A megawatt (MW) is one million Watts.

Capacity is not the energy itself, or the physical facility, but a measure of the *ability* to convert the energy into electricity.

Q. Does MISO need or use capacity?

A. Yes. MISO needs sufficient capacity -- rate of energy conversion -- to provide sufficient electric energy to customers in the time frame that customers want to use that energy, in short, "demand" energy, at specific times. MISO's "resource adequacy" label refers to the principle of satisfying that demand, subject to a standard of performance. MISO controls the dispatch of all physical capacity in the region and uses all resources to serve all demand in the region. How that capacity is provided and who pays for it is the issue that the SRM capacity charge addresses.

Q. Is capacity sold and bought in the MISO region, and if so, how?

A. Actual physical capacity is not sold or bought. Instead, financial rights to the market value of capacity are sold and bought. MISO awards a qualified capacity resource a Zonal Resource Credit ("ZRC"), which is a financial instrument that represents one MW of capacity dedicated to MISO for a specified time period. The owner of a Zonal Resource Credit has the following rights:

1. The right to set the price for the ZRC that is offered into the MISO auction.
2. If the ZRC "clears" (is selected in) the auction, the right to receive the Auction Clearing Price from MISO.
3. The right to sell the above two rights to another party.

Q. Why is the Staff proposing CONE as an alternative method to determine the SRM capacity charge?

A. The Staff lists several issues with the current method of determining the SRM capacity charge from embedded utility cost and its related adjustments:

> Since the initial approval of the current method of calculating the SRM capacity charge and associated rates, Staff has become aware of several potential issues with that method.
>
> For example, the required reconciliation of projected energy sales revenue net of fuel costs to the actuals, calculated as the value of the Company's generation at the locational marginal price (LMP), has the potential to drive the capacity charge unreasonably low or high depending on the relationship between the Company's costs to produce that energy and both actual and projected LMPs. In addition, the current capacity charge method produces increasingly questionable results the more a utility relies on purchased power agreements for the provision of power to its customers.
>
> For these reasons, Staff is presenting an alternative method for calculating the SRM capacity charge and revenue requirement, consistent with its proposal in the initial set of SRM cases. [8]

Q. Do you agree with these issues?

A. Yes, and there are many more issues with the current implementation of the SRM capacity charge:

[8] Mr. Revere, direct testimony, page 9, lines 1-11. Emphasis and spacing added.

(a) Correct reconciliation of projected to actual costs is impossible, as discussed in section I previously;

(b) The SRM current implementation ignores the multiple methods (geared to the economics of the MISO auction) by which a supplier can satisfy its capacity obligations to MISO;

(c) Illogically, utilities are allowed to meet an AES's capacity obligation to MISO using the identical process that AESs are barred from using -- simply paying MISO's capacity charge;

(d) The SRM statute and current implementation disregard the MISO tariff rules that do not allow assigning one supplier's obligations to a different supplier.

(e) The SRM statute was obsolete when enacted in 2016, because it ignored the fact that MISO began dispatching all generation to serve all load in April, 2005, and thus it is not true that a supplier serves its own load with physical capacity that it owns;

(f) The statute became further obsolete with the creation of the MISO annual auction in 2013, which effectively set the price (Auction Clearing Price) which suppliers pay and owners of capacity rights receive. The SRM statute erroneously assumes that MISO requires suppliers to own capacity.

(g) After its enactment in 2016, the SRM statute has become further obsolete with the creation of the MISO seasonal capacity obligations in the 2022/2023 planning year. Auction prices are now seasonal, CONE is seasonal, and MISO may charge multiples of CONE for a season, not a year.

(h) Finally, the latest of events that has made the current implementation of the SRM statute obsolete, on July 2, 2024, MISO received FERC approval for a Reliability Based Demand Curve ("RBDC"), which is a different method of setting auction prices on July 2, 2024; plus, there is an RBDC "opt out" provision.

The SRM statute itself has no effect on reliability/resource adequacy -- the statute does not affect supply, does not affect demand, does not improve the performance of generating units or reduce the volatility of demand fluctuations over time. Current implementation methods are sinking the SRM implementation under its own weight, so to speak, from the complexities of compensating for the flaws in the statute.

It is time for the Commission to take a fresh look at the implementation of the SRM statute and create a fair and workable implementation method based on the cost-of-service statute, MCL 460.11(1).

Q. Is the Staff's proposal to use CONE as the SRM capacity charge a reasonable solution?

A. Until MISO switched to a seasonal resource adequacy construct in the 2022/2023 planning year, the CONE concept would have been workable, providing the total context was tended to. As the Staff notes, it proposed a CONE option in the original SRM cases in 2017: "an alternative method for calculating the SRM capacity charge and revenue requirement,

consistent with its proposal in the initial set of SRM cases."[9] Now, however, the circumstances are different, as explained later in my testimony.

Q. What was the context for Energy Michigan's proposal in the initial SRM case?

In DTE's initial SRM case, U-18248, Energy Michigan also proposed that the SRM capacity charge be set to CONE, in the context of its total recommendation. The discussion at the time was how to apportion costs if new capacity had to be built with Michigan. Both CONE and the auction price were part of Energy Michigan's proposed solution.

A critical part of Energy Michigan's solution was to allow AESs -- or any supplier -- to use the same methods of satisfying the MISO requirement as the utility would be able to use if the utility were required, under the SRM statute, to satisfy the AES's obligations to MISO. Namely, as DTE testified to at the time, if DTE were short of capacity, it would use the MISO auction. However, the current implementation process is that AESs are barred from using the MISO auction in demonstrating sufficient capacity under the SRM statute, and so consequently AESs could pay the utility the SRM capacity charge only to have the utility use the MISO auction to satisfy the AES's obligation to MISO. It did not, and does not, make sense.

Energy Michigan's proposal was this: If a supplier could use any of the MISO options in the MISO tariff to meet its capacity obligations -- including use of payment of the auction

[9] Mr. Revere, direct testimony page 9, lines 10-11.

price -- then Energy Michigan proposed that the SRM capacity charge be set to CONE as an incentive for a supplier to fully participate in the MISO process. CONE was an incentive because at that time the auction price could be no higher than CONE. Essentially, why pay CONE to a utility when the MISO auction price could never be greater than CONE and could well be less than CONE?

Q. Could a utility use its extra capacity to satisfy an AES's capacity obligation to MISO?

A. Since all capacity has to be offered into the MISO auction, MISO is already paying the Auction Clearing Price ("ACP") per MW to the utility for the utility's extra capacity. "Using" extra capacity to satisfy an AES's capacity obligation to MISO simply means taking the ACP money from MISO and then giving the ACP money back to MISO to satisfy the MW of the AES's obligation, which MISO charges at the same ACP price per MW. It is not the extra physical capacity that is being used, it is the money foregone from getting paid the ACP by MISO for the extra capacity.

Q. Could setting the SRM capacity charge to CONE work, and in what context?

A. Setting the SRM capacity charge could work, in theory, if an AES could use any of the MISO options in the MISO tariff to meet its capacity obligations -- including payment of the auction price, which is the same option as the utility to which the AES pays the SRM capacity charge has. The SRM statute appears to allow this.[10] Further, the utility and the

[10] "A capacity charge shall not be assessed for any portion of capacity obligations for each planning year for which an alternative electric supplier can demonstrate that it can meet its capacity

AES are on equal terms in the definition of "electric provider,"[11] so if the utility is able to participate in the MISO auction to satisfy an AES's capacity obligation to MISO, then the AES should also be able to participate in the MISO auction. I realize that this is different from the present implementation process.

Q. If suppliers were able to use the MISO auction, would that negate the intent of the SRM statute?

A. The SRM statute was a negotiated deal, not a solution to a visible and mutually acknowledged problem. I am not addressing the intent; I am addressing the practical and real consequences and ramifications of the statute. As explained previously, the SRM statute has no practical effect on reliability/resource adequacy. If all suppliers -- not just the utility -- were able to use the MISO auction, that fact would not change. Reliability/resource adequacy would remain the same.

Q. You qualified your previous answer on the workability of CONE with "in theory." Could setting the SRM capacity charge at CONE work <u>in practice</u> at this time?

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obligations through owned or contractual rights to any resource that the appropriate independent system operator allows to meet the capacity obligation of the <u>electric provider</u>. The preceding sentence <u>shall not be applied in any way that conflicts with a federal resource adequacy tariff</u>, when applicable." [MCL 460.6w(6). Emphasis added.]

[11] "<u>Electric provider</u>" means any of the following:
(i) any person or entity that is <u>regulated</u> by the commission for the purpose of selling electricity to retail customers in this state.
(ii) a municipally owned retail utility in this state.
(iii) a cooperative electric utility in this state.
(iv) an <u>alternative electric supplier</u> licensed under section 10a.
[MCL 460.6w(12)(c). Emphasis added.]

A. At this time, with the recent changes in how MISO imposes capacity obligations and runs the auction, setting the SRM capacity charge to an annual CONE would create a number of complexities that didn't exist a few years ago.

First, MISO now imposes capacity obligations by season, four seasons per year, not annually. The obligations extend only three months. Zonal Resource Credits now have a 3-month term, not a 12-month term. Therefore, the demonstration of capacity sufficiency under the SRM statute now can be done only by season.

Second, since 2022, the auction is now run by season, and therefore each zone in MISO sees four auction prices per year, not one. Therefore, a single annualized CONE does not fit a utility's cost of satisfying a supplier's capacity obligations to MISO.

Third, it is possible for the Auction Clearing Price for a single season to be CONE, or 1-1/3 times CONE, or two times CONE, or four times CONE, depending on the clearing prices for the other seasons. CONE is approximately $350 per MW-day. Therefore, a utility could be placed in a position of collecting $350 per MW-day from a supplier yet paying MISO $1,400 per MW-day (4 x CONE) for 90 days to satisfy the supplier's capacity obligations to MISO. This does not fairly follow cost-of-service principles. Plus, it would open the door to gaming by a supplier to play the cost of its obligation to MISO against the cost of paying an SRM capacity charge of CONE to the utility.

Fourth, in July 2024, a month ago, MISO received approval for a new method of running the auction, using what economists call a "sloped demand curve," which MISO labels a "Reliability Based Demand Curve," or RBDC. This will result in auction clearing prices that are higher than the highest priced capacity that is needed to meet the total MISO region capacity requirement. Further, there is choice to "opt out" of the RBDC in return for paying a higher price for a number years.

In short, while CONE is still the "cost of new entry" in economic terms, figuring out the cost of a supplier's obligation to MISO -- and how long that obligation will endure -- is not a task that can be compared to CONE in a straightforward and easily visible way, under MISO's current processes. Applying an annualized CONE value to MISO capacity obligations now determined, valued, and paid by season does not reflect cost-of-service principles and may conflict with the cost-of-service statute MCL 460.11(1).

Q. Is there a specified cost, similar to the CONE concept, that can work for an SRM capacity charge?

A. Yes. The specified charge would be the MISO zonal charge per MW for the applicable season. In light of the current complexities of determining an SRM capacity charge calculation that somehow reflects the present MISO price of satisfying capacity obligations -- if such is possible at all -- the Commission can go to straight cost reimbursement -- cash out the door, so to speak -- supported by the cost of service statute MCL 460.11(1) cited previously. It would work as follows:

a. The Commission still would require suppliers to demonstrate capacity per the current SRM statute, but the demonstration would be changed from annual to four seasons.

b. If an AES does not demonstrate sufficient capacity -- for example is 10 MW short in the 90-day winter season -- then the Commission would use the MISO zonal charge per MW for the winter season to determine the AES's capacity obligation to MISO. In this example, if the MISO winter zonal price were $15 per MW-day, then the charge for 10 MW would be: 10 MW x 90 days x $15 = $13,500.

c. The AES would pay the utility $13,500.

d. The utility would satisfy the AES's obligation to MISO. Although at present the mechanics of exactly how the utility would do this is unclear, if the Commission sees it can be done under the present implementation process then it can be done in the same way in the process described above. Regardless, the cost to the utility -- cash out the door or foregone cash in the door -- is $13,500.

Q. What are the benefits of Energy Michigan's proposal?

A. There are several benefits:

1. The proposal resolves the conflict between the SRM statute, which in many parts does not make sense, and the cost-of-service statute, which can look to actual and visible cash costs, not just allocations or estimates or imputed costs, or illogical costs such as true-up adjustments.

2. The utility is made whole for costs it has expended to satisfy the AES's obligations.

3. AESs (and other suppliers) pay exactly for the benefits they receive. Potential gaming is eliminated.

4. Utility bundled customers are neutral. They neither benefit from extra money coming in or make up any additional costs that the utility does not receive from the AES.

5. Utility stockholders are neutral.

6. No adjustments are needed. No offsets, no reconciliations, no differences over the scope of energy market sales, no contest over proper fuel expenses, etc.

7. Efforts and time spent to set the SRM capacity charge, and the present contests and debate over such setting, annually for six utilities, are

eliminated. Further, a need to set the SRM capacity charge for each of four MISO seasonal capacity obligations -- four times the current effort -- is also eliminated. Nothing would have to be done unless and until a supplier became subject to the SRM capacity charge, which has never happened in seven years. If so, then the Commission would merely apply the MISO zonal charge per MW for the season.

Q. Under this process, would utility full service customers and AES customers be charged the same for capacity?

A. Yes. The relevant clause in the SRM statute states, "the commission shall . . . ensure that the resulting capacity charge does not differ for full service load and alternative electric supplier load."[12] Utility full service customers pay both capacity and non-capacity costs, while AES customers that the SRM capacity charge would pay only capacity costs. The Staff's proposed method would make the capacity costs the same for both full service and AES customers by using a percentage in allocating costs to full service customer such that the amount of costs apportioned to full service customers are equal to CONE -- the same charge that AES customers would pay. The Staff explained:

> **Q. What costs would be identified as capacity-related under this method?**
>
> A. Costs currently allocated using the production cost allocator and other capacity-related costs would be the starting point for this determination. Then the percentage applied to determine which of those costs are capacity-related would be set at the percentage necessary to make the resulting amount equal to CONE or some other measure of the value of capacity, as determined by

[12] MCL 460.6w(3).

> the Commission. This would treat all costs in excess of CONE (or the Commission's chosen value of capacity) as non-capacity-related costs. [13]

Q. How would this apply to a specified cost other than CONE?

A. Thus, if instead of CONE, the percentage target were simply changed to a different specified cost, namely, "the percentage necessary to make the resulting amount equal to [~~CONE~~] the MISO zonal charge per MW for the season," then the same result would be achieved -- both utility full service and AES customers would pay the same charge for capacity.

Q. What is your conclusion?

A. Given the changes to MISO's resource adequacy process since 2022, it is time to recognize those changes by implementing a simpler, more accurate, more efficient, and transparent way of compensating the utility for taking on the capacity obligations to MISO of another supplier. If the Commission does not believe that such sweeping changes can or should be made in this proceeding or on this record alone, then I would encourage the Commission to reopen the SRM docket in order to fully vet this and any other proposals to address the issues with the current SRM process identified in the testimony and rebuttal in this proceeding.

Q. Does that complete your direct testimony?

A. Yes, it does.

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[13] Mr. Revere, direct testimony, page 11, lines 1-7. Emphasis added.

MR. OOMS: Thank you, your Honor. That is all that I have.

JUDGE WALLACE: All right. Thank you, Mr. Ooms. All right. Moving on, Ms. Brader.

MS. BRADER: Thank you, your Honor. On behalf of the City of Ann Arbor, I will be moving to bind into the record the prefiled direct testimony of four witnesses, along with the exhibits sponsored by those witnesses.

First, I move to bind into the record the prefiled Direct Testimony of Tiffany Giacobazzi, consisting of a cover page and eight pages of questions and answers. With that testimony, she sponsors four exhibits, designated AA-1 through AA-4, and I move to admit those exhibits into the record.

JUDGE WALLACE: O.K. Thank you. Is there any objection to binding in the direct testimony of Ms. Giacobazzi?

Hearing none, the testimony is bound in.

Is there any objection to the admission of Exhibits AA-1 through AA-4?

Hearing none, those exhibits are admitted.

(Testimony bound in.)

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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.	U-21534

DIRECT TESTIMONY OF TIFFANY GIACOBAZZI

ON BEHALF OF

THE CITY OF ANN ARBOR

July 26, 2024

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Tiffany Giacobazzi. I am the Urban Forestry & Natural Resources Planning Coordinator for the City of Ann Arbor, Michigan. My office is located at 4251 Stone School Road, Ann Arbor, MI 48108.

Q. On whose behalf are you submitting your testimony in this proceeding?

A. My testimony is on behalf of the City of Ann Arbor ("Ann Arbor" or "the City").

Q. Have you previously testified before this Commission or in other proceedings?

A. Yes. I testified on behalf of Ann Arbor in Case No. U-20836.

Q. What is your educational background?

A. I have a bachelor's degree in forestry from Michigan Technological University, where I also minored in ecology.

Q. What is your professional background?

A. I have spent the last 15+ years working with communities, local, state, and federal governments, non-profit groups, private landowners, utility companies, and students on numerous projects, programs, and workshops related to urban forestry. I have been an International Society of Arborists ("ISA") Certified Arborist for 15 years, an ISA Tree Risk Assessment Qualified Arborist for 10 years, and recently earned my certification as an ISA Certified Arborist Municipal Specialist. I have managed two state urban forestry programs (South Dakota and Indiana) and two municipal programs (Novi and Ann Arbor). I served as President of ISA, Michigan during 2021. In addition, I worked in the past as a Systems Arborist for ACRT, Inc., where I built and managed a Vegetation Management Program for 5,400 miles of overhead utility lines. I have been in my current

position as the Urban Forestry and Natural Resources Planner for the City of Ann Arbor for over 5 years.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss Ann Arbor's tree trimming practices, my findings based on Ann Arbor's tree damage and pruning data, and the impacts of tree health on power outages.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit AA-1	Curriculum Vitae of Tiffany Giacobazzi
Exhibit AA-2	Tree Trimming Detailed Specifications
Exhibit AA-3	Tree Damage and Pruning Habits - 2018 to present
Exhibit AA-4	Tree Damage and Pruning Habits - 2024 YTD

II. ANN ARBOR'S TREE TRIMMING PRACTICES

Q. How often does Ann Arbor trim its City-owned street trees?

A. The City is currently in the eighth year of a 10-year tree-trimming cycle, which was implemented in 2017. That means that at some point during the 10 years from 2017 to 2026, the City trimmed (or will trim) all City-owned street trees to its tree trimming standard at least once. The City also trims its trees reactively as needed.

Q. What is the standard to which City-owned street trees are trimmed?

A. City-owned street trees are trimmed to a clearance of 15 feet around roadways and to a clearance of 10 feet around sidewalks. Trimming to the City's standard also includes, but is not limited to, removal of all dead, diseased, broken, or crossing branches that are two inches or more in diameter, leaving trees' crowns as balanced as possible, and making

clean cuts sufficiently close to the trunk or parent limb to allow for proper wound closure. For detailed trimming specifications, *see* Exhibit AA-2.

Q. Is the City on track to complete its current 10-year tree trimming cycle on time?

A. Yes, the City is on track to complete its current 10-year tree trimming cycle in 2026 as planned.

Q. Will the City continue on a 10-year tree trimming cycle going forward?

A. The City intends to move to a 7-year trimming cycle after the completion of the current 10-year cycle.

Q. Why does the City intend to move to a shorter tree trimming cycle in the future?

A. Once the City completes the current tree trimming cycle (in which all City-owned street trees will have been trimmed to the City's standard at least once), it is anticipated that it will take less work and time to trim and maintain those trees to the standard. Thus, Ann Arbor anticipates having the resources (e.g., budget and workforce) to maintain a 7-year tree trimming cycle after the completion of the current cycle.

Q. What are the main goals of the City's tree trimming program?

A. The main goal of the City's tree trimming program is safety. Roadways need to be clear of overhang to allow the safe passage of emergency vehicles and snowplows (as well as civilian traffic), and sidewalks need to provide clearance for pedestrians to safely walk without running into obstacles and without the danger of being struck due to a tree failure. The second priority is the health of the City street trees. Routine trimming creates a healthier tree canopy due to removing dead, dying, or diseased limbs, as well as earlier identification and correction of insect and disease problems. Other major goals include preventing storm damage and avoiding the costs of reactive maintenance, such as the

trimming or removal of damaged trees.

III. FINDINGS BASED ON ANN ARBOR TREE DAMAGE DATA

Q. Is there evidence that trimming trees to the City's standard prevents storm damage and/or avoids reactive maintenance costs?

A. Yes. The City keeps records of when each street tree was last trimmed to the City's standard. The City also tracks when it responds to and performs maintenance on damaged street trees. Based on the City's data, it has responded to 1,437 damaged trees since January 1, 2018, and of those damaged trees 836 had never been trimmed to the City's standard.[1] See Exhibit AA-3. That means that over 58% of reactive tree maintenance was performed on trees that had not been trimmed to the City's standard. In other words, over the past six and a half years, a City tree that had never been trimmed to our standard was 1.4 times more likely to require reactive maintenance than a City tree that had been trimmed to the City's standard within the prior 7 years.

Reviewing the data from the current year reveals similar statistics. Since January 1, 2024, the City has responded to 87 damaged trees. Of those 87 trees, 47 (or just over 54%) had never been pruned to the City's standard.[2] Exhibit AA-4.

Q. What does the City's data indicate about the frequency of reactive maintenance for trees that were trimmed to the City's standard within the last five years?

A. The data on City trees going back to January 1, 2018 demonstrates that trees that had been trimmed to the City's standard less than five years prior to being damaged made up only approximately 37% of reactive maintenance. In other words, City street trees that

[1] This data is accurate as of July 16, 2024.
[2] This data is accurate as of July 16, 2024.

either had never been trimmed to the City's standard or had been trimmed to the City's standard five or more years prior to being damaged were 1.7 times more likely to need reactive maintenance than trees that had been trimmed to the City's standard less than five years prior to being damaged. Exhibit AA-3.

The data from 2024 so far shows that of the 87 damaged street trees the City has responded to, only 25 (less than 29%) had been trimmed to the City's standard less than five years ago. Exhibit AA-4. That means City trees that either had never been trimmed to the City's standard or had been trimmed to the City's standard five or more years ago were 2.1 times more likely to need reactive maintenance this year than trees that had been trimmed to the City's standard less than five years ago.

Q. What do these findings indicate to you about the importance of regular tree trimming?

A. These findings indicate that getting all City trees trimmed to our standard and then maintaining a regular tree trimming cycle should result in the need for less reactive maintenance, which will save the City money, time, and resources while maintaining healthier trees.

IV. IMPACTS OF TREE HEALTH ON OUTAGES

Q. On page 4 of her direct testimony, DTE witness Rachel C. Steudle testified that "tree interference remains one of the leading drivers of customer outages," and that "[h]istorically, tree-caused outages accounted for two-thirds of the time that customers spent without power." In your opinion, and based on Ann Arbor's experience, what would be the best way to reduce outages caused by tree interference?

A. The best way to reduce outages caused by tree interference would be to perform preventive trimming around power lines as often as possible. Regular trimming improves the health of trees by eliminating dead or dying branches, crossing or rubbing branches, and weak branch unions. A healthy, properly trimmed tree is less likely to fail in a way that may interfere with a power line than a tree that is not properly maintained.

Q. If DTE fell behind on its tree trimming cycle, would you expect any impact on outages caused by tree interference?

A. Yes. If DTE fell behind its trimming cycle, I would expect the number of outages due to tree interference to be greater than if DTE maintained its trimming cycle.

2Q. If DTE fell behind on its tree trimming cycle, would you expect any impact on DTE's storm restoration costs?

A. Yes. If DTE fell behind its trimming cycle, I would expect its storm restoration costs to be higher than if it maintained its trimming cycle.

Q. Why would you expect storm restoration costs to be higher if DTE fell behind its tree trimming cycle?

A. Falling behind on a tree trimming cycle means fewer trees have been trimmed than planned, and that means there are more trees than expected with limbs and branches within a close proximity to power lines than there would be if DTE had remained on cycle. Branches and limbs that are not trimmed to the standard clearance are more likely to interfere with power lines should they fail. Thus, I would expect storm restoration costs to increase at a rate that approximately corresponds with the rate that DTE fell behind on trimming. Said another way, the more DTE falls behind on its tree trimming schedule, the more storm restoration costs will go up.

Q. Are you aware of how methane leaks from underground pipelines impact vegetation?

A. Yes. The presence of methane underground results in soil with low oxygen concentration and high carbon dioxide concentration. Trees or other vegetation with roots in that soil often die or suffer damage due to the lack of oxygen. It is common for trees in the resulting oxygen-depleted soil to die from the top down, so a thinning crown is often a symptom of methane exposure.

Q. Would you expect trees exposed to methane in their root systems to cause any greater risk of power outages than trees in healthy soil?

A. Yes. As indicated above, trees exposed to methane generally die from the top down, the result being dead branches at the crown. These branches are more likely than lower branches to impact power lines should they fail. They are also more likely to fail (i.e., break loose) – both on a clear day or during a storm – due to their unhealthy condition. Thus, I would expect trees exposed to methane to pose a greater risk of causing outages than trees in healthy soil.

Q. Have you personally witnessed street trees in Ann Arbor that exhibit this kind of damage?

A. Yes.

Q. To your knowledge, has DTE Gas or DTE Electric ever contacted the City to report possible methane damage to a street tree or notified the City it would be trimming a street tree to address dead branches at the crown due to methane damage?

A. No.

Q. Does this conclude your direct testimony?

A. Yes.

Q. Do you swear under penalty of perjury that the statements above are true to the best of your knowledge, information, and belief?

A. Yes.

Tiffany Giacobazzi

Tiffany Giacobazzi

MS. BRADER: Next, I move to bind into the record the prefiled Direct Testimony of Cyrus Naheedy, consisting of a cover page and nine pages of questions and answers. With that testimony, he sponsors seven exhibits, designated AA-5 through AA-11, which I move to admit into the record.

JUDGE WALLACE: Is there any objection to binding in the testimony of Mr. Naheedy?

Hearing none, the testimony is bound in.

Is there any objection to the admission of Exhibits AA-5 through AA-11?

Hearing none, those exhibits are admitted.

(Testimony bound in.)

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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.	U-21534

DIRECT TESTIMONY OF CYRUS NAHEEDY

ON BEHALF OF

THE CITY OF ANN ARBOR

July 26, 2024

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Cyrus Naheedy. I am a Transportation Engineer for the City of Ann Arbor, Michigan. My office is located at 301 E. Huron Street, Ann Arbor, MI 48104.

Q. On whose behalf are you submitting your testimony in this proceeding?

A. My testimony is on behalf of the City of Ann Arbor ("Ann Arbor" or "the City").

Q. Have you previously testified before this Commission or in other proceedings?

A. No.

Q. What is your educational background?

A. I have a Master of Science in Transportation Planning and Engineering from the Polytechnic Institute of New York University and a Bachelor of Science in Industrial & Operations Engineering from the University of Michigan.

Q. What is your professional background?

A. I have spent the past 14 years working as a transportation engineer for both private companies and public bodies in the states of New York and Michigan. I have been in my current role as a Transportation Engineer for the City of Ann Arbor for over 5 years.

Q. Are you testifying today as an expert witness, fact witness, or both?

A. I am testifying in both capacities. I am an expert in transportation engineering, and in my role, I support the planning and maintenance of City-owned streetlights. I am also presenting first-hand factual testimony related to specific interactions with DTE Electric Company ("DTE" or "the Company") in my current position.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss Ann Arbor's DTE Streetlight Conversion

Project, as well as interactions with DTE relating to streetlighting in Ann Arbor.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit AA-5	Curriculum Vitae of Cyrus Naheedy
Exhibit AA-6	Excerpt of Direct Testimony of Raymond Hess (Case No. U-20836)
Exhibit AA-7	Discovery Response DEMAUI-2.1 from Case No. U-21297
Exhibit AA-8	Purchase Agreement for LED streetlights
Exhibit AA-9	DTE Community Lighting Catalog
Exhibit AA-10	Letter from DTE dated February 19, 2024
Exhibit AA-11	Discovery Response MAUIDE-4.19a

II. STREETLIGHT RELIABILITY

Q. In past years, Ann Arbor staff have testified in DTE Electric rate proceedings regarding concerns with streetlight reliability. Do you still have these concerns?

A. Yes. I have attached an excerpt of former Ann Arbor staff member Raymond Hess's past testimony regarding streetlight reliability from Case No. U-20836. Exhibit AA-6. Streetlight reliability continues to be a concern for Ann Arbor, both because of the long restoration time and the high number of outages. For instance, from 2020 through 2022, Ann Arbor's City-owned streetlights experienced an average annual outage rate of approximately 9%, while DTE-owned streetlights in Ann Arbor experienced an average outage rate of approximately 26%. Exhibit AA-7. Moreover, the average duration of DTE-owned streetlight outages, which was 3.60 days in 2017, was up to 4.7 days in

2022, and according to very limited data[1] was 4.16 days in 2023. Exhibit A-25, Schedule O1. Interestingly, the format of DTE's outage reporting to the City changed in October of 2023 in a way that makes it more difficult for the City to identify the start date of outages in a way consistent with past reporting, but my impression from my day-to-day work is that DTE's outage response and restoration time is very similar to past years.

Q. Are there any steps the City is taking in regard to DTE-owned streetlights that it hopes will improve streetlight reliability?

A. Yes. The City has secured grant funding to convert all remaining DTE-owned HID streetlights to LEDs, which will involve new fixtures on existing streetlight poles, as I will discuss more in the next section of my testimony. While there are many potential benefits from the project, one expected benefit of having so many new fixtures in place of aged and outdated fixtures is improved reliability.

III. ANN ARBOR'S STREETLIGHT CONVERSION PROJECT

Q. What is Ann Arbor's Streetlight Conversion Project?

A. The Streetlight Conversion Project is the City's plan to use funds from a Carbon Reduction Grant it was awarded in March 2023 from the Southeast Michigan Council of Governments ("SEMCOG") to transition all DTE-owned and maintained streetlights in Ann Arbor from high intensity discharge ("HID") fixtures – the majority of which are high pressure sodium ("HPS") – to light emitting diode ("LED") fixtures in an effort to further the City's goals of advancing sustainable practices and decreasing its carbon

[1] DTE retired its old outage management system ("OMS") in January 2023 and did not migrate to its current OMS until October 2023. DTE claims its interim OMS could not calculate duration metrics, so it only included duration metrics from the current OMS for 2023 (i.e., October forward). Exhibit A-25, Schedule O1.

footprint. A total of 4,087 streetlights will be converted from lower efficiency HIDs to higher efficiency LEDs pursuant to this program.

Q. Why is Ann Arbor transitioning from HID streetlights to LED streetlights?

A. LED streetlights are more environmentally and financially sustainable than HID streetlights. They last longer and use less energy, which means less maintenance and lower operating costs. Moreover, LED fixtures have become the standard technology for streetlighting. In fact, DTE notified its community lighting customers in November 2023 that its streetlight manufacturers discontinued the production of HPS streetlights and that it would begin replacing failed HPS streetlights with LEDs after its existing inventory of HPS streetlights was depleted. Exhibit A-25, Scheduled O3.

Q. Is there a cost to the City for transitioning DTE-owned and maintained streetlights from HID to LED pursuant to its Streetlight Conversion Project?

A. Yes. DTE requires customers who convert "early" from HID to LED to pay a contribution in aid of construction ("CIAC") equal to the total construction cost, including labor, materials, and overhead. In this case, that means Ann Arbor will pay $1,021,700.97 for the conversion of 4,087 streetlights. Exhibit AA-8. As indicated above, the City is able to make this investment because a large portion of the cost is being covered by a Carbon Reduction Grant from SEMCOG.

Q. What is the timeline for the Streetlight Conversion Project?

A. The Streetlight Conversion Project can be broken into four main phases: (1) public engagement, (2) grant acceptance, (3) environmental review, and (4) installation. The public engagement step, which included installing sample lights of different wattages and color temperatures and surveying people about them, began in December 2023 and was

completed in January 2024. We are now in the grant acceptance phase. We expect installation will begin in the fall or winter of 2024 with a completion date in 2025, pursuant to a Purchase Agreement with DTE (Exhibit AA-8) that is pending approval from the Ann Arbor City Council.

Q. Can you describe the lights that were considered as part of the public engagement phase?

A. The City wanted all sample streetlights to meet lighting standard IES RP-8, have a correlated color temperature no higher than 3000K, and restrict the amount of upward-directed light. We felt these criteria would meet the goals of reducing the environmental impact from the streetlights by lowering energy usage and responding to commonly expressed concerns regarding light trespass and how "blue" the light from DTE's standard offerings is. The City had DTE install four sample LED streetlight options at two locations in the City during the winter of 2023-2024. None were "standard offerings" from DTE because all of them had a color temperature lower than what DTE normally offers. Exhibit AA-9. The sample LED streetlights at each location included two low wattage fixtures (29W) and two medium wattage fixtures (58W), and each wattage had two color temperature options (2700K and 3000K), so that the resulting choices were: 29W/2700K, 29W/3000K, 58W/2700K, and 58W/3000K.

Q. What did you learn about public preferences regarding streetlights from the samples installed?

A. The City sought input regarding the public's preferences through a survey, which was open for 5 weeks, during which 56 responses were collected. The public feedback clearly favored streetlights with warmer (i.e., lower) color temperatures. While there was no

clear consensus on wattage, the survey also suggested that most respondents thought the medium wattage option (58W) could be appropriate (i.e., they answered "Yes" or "Maybe") to install on residential streets. In an experience that is common to other public comment exercises, every light had some individual responses saying the light was too bright, and others saying it was too dim.

Q. If DTE had a 58W streetlight with a lower color temperature as one of its standard offerings, would the City have considered it?

A. Absolutely. One of the most time-intensive aspects of this project has been attempting to determine what the requirements would be if the City did not use a standard offering from DTE, especially regarding the amount of storage space we would have to provide and the extra amount we would have to spend on backstock. These added practical and cost considerations had to be weighed when considering whether we wanted a single model of light or more than one model of light (e.g., different wattages for different locations). Had there been a standard offering of a lower color temperature, we would certainly have considered it as a way to both meet our goals and avoid these extra costs and practical considerations.

Q. Besides public feedback and costs like those described above, were there other factors the City considered when determining the optimal wattage and color temperature for LED streetlights in the City?

A. Yes. The City tried to balance many different considerations, with safety and sustainability being the main areas of focus. It is important to the City that the streetlights it chooses to install will promote pedestrian safety, reduce energy usage, reduce energy costs, and avoid light pollution.

Q. Based on these considerations, what wattage and color temperature did Ann Arbor staff recommend for the City's streetlights?

A. Based on these considerations, in addition to the feedback from our public engagement, we determined that LED streetlights with a wattage of 58W and a color temperature of 2700K would meet streetlighting needs for the majority of the City.

Q. What are the consequences to the City for opting to install LED streetlights other than those normally provided by DTE?

A. As I mentioned before, because Ann Arbor's LED fixture of choice is not DTE's recommended LED fixture, and thus, not part of DTE's standard stock, it is considered a special-order material ("SOM") fixture. This means that Ann Arbor is responsible for maintaining a backstock of inventory of its chosen LED fixtures to address outages that require replacements. While DTE generally requires customers who request non-standard offerings to maintain a backstock of 10% of the total quantity installed, which is what Ann Arbor was initially told would be required, in negotiations that occurred after the briefing closed in the last rate case when the City described those additional costs, DTE has agreed to reduce its inventorying requirement. *See*, Exhibit AA-10. To ensure prompt replacement should an outage occur, the City plans to initially procure and store an additional 80 of its chosen LED streetlight fixtures (approximately 2% of the total quantity), which will cost the City approximately $25,000 for the fixtures plus the costs associated with warehousing and managing this backstock, in addition to the $1,021,700.97 CIAC the City is paying to DTE for the installation of 4,087 LED fixtures. We feel 2% is a good balance between keeping an initial backstock sufficient to ensure outages are not of an extended duration and the costs associated with purchasing and

maintaining backstock for brand-new lights.

Q. If, instead of pursuing this conversion project with DTE, Ann Arbor waited until each of its remaining HID fixtures failed, would the City eventually have all LED streetlights with no requirement to pay a CIAC?

A. Yes. As indicated above, DTE notified its streetlighting customers that once its stock of HPS fixtures is depleted, it will begin replacing failed HPS fixtures with LED fixtures. Moreover, according to DTE's response to a discovery request by the Michigan Municipal Association for Utility Issues, Ann Arbor would not have even had to wait for DTE's inventory of HPS fixtures to be depleted: "In the event of a failed HPS fixture – upon request, the Company is amendable to replacing with an equivalent LED fixture. In such cases, customer contributions are not required." Exhibit AA-11.

Q. Why is Ann Arbor going forward with proactively converting to LED streetlights rather than waiting for its HPS fixtures to fail?

A. There are several reasons. The first reason is economic: the City was awarded a grant that covers the bulk of the CIAC Ann Arbor must pay, making the investment financially feasible for the City due to the annual energy cost savings once all lights are converted. The second reason is that Ann Arbor does not want its HPS fixtures to be replaced with any of DTE's current standard offering LED fixtures because they are too high a color temperature. Therefore, if it wanted to meet its other goals, the City would have to pay some amount of money up front to have the LED fixture of its choice installed because it is a "special order material" fixture. Thus, it makes financial sense for Ann Arbor to use the grant funds to have its preferred streetlights installed. The last reason is that the sooner HPS fixtures can be replaced with LED fixtures, the sooner the City will begin

realizing the beneficial environmental and financial impacts of transitioning to LEDs (e.g., reduced energy consumption, less light pollution, etc.).

Q. Does it feel fair that Ann Arbor will pay up front to convert to LEDs, but not receive any recognition that it has relieved other customers of paying for Ann Arbor's conversion costs?

A. No. I think the City should get a credit on its bill equal to the monies other customers will not have to pay to convert the City's streetlights. Otherwise, the City is paying to help with the installation costs for other customers making this transition, but they are not paying anything to help with our transition.

Q. Does this conclude your direct testimony?

A. Yes.

Q. Do you swear under penalty of perjury that the statements above are true to the best of your knowledge, information, and belief?

A. Yes.



Cyrus Naheedy

JUDGE WALLACE: Please go ahead.

MS. BRADER: Sorry, your Honor, I couldn't get it to unmute. Next, I move to bind into the record the prefiled testimony of Skye Stewart, consisting of a cover page and eight pages of questions and answers. With that testimony, she sponsors three exhibits, designated AA-12 through AA-14, which I move to admit into the record.

JUDGE WALLACE: Is there any objection to binding in the testimony of Ms. Stewart?

Hearing none, the testimony is bound in.

Is there any objection to the admission of Exhibits AA-12 through AA-14?

Hearing none, those exhibits are admitted.

(Testimony bound in.)

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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.	U-21534

DIRECT TESTIMONY OF SKYE STEWART

ON BEHALF OF

THE CITY OF ANN ARBOR

July 26, 2024

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Skye Stewart. I am the Chief of Staff for the Public Services Administration for the City of Ann Arbor, Michigan. My office is located at 301 E. Huron Street, Ann Arbor, MI 48104.

Q. On whose behalf are you submitting your testimony in this proceeding?

A. My testimony is on behalf of the City of Ann Arbor ("Ann Arbor" or "the City").

Q. Have you previously testified before this Commission or in other proceedings?

A. Yes. I testified on behalf of Ann Arbor in Case Nos. U-21297 and U-21291.

Q. What is your educational background?

A. I have a Bachelor's degree in political science and sociology from Birmingham-Southern College and a Master of Public Policy and public administration from the Gerald R. Ford School of Public Policy at the University of Michigan.

Q. What is your professional background?

A. My career is in public administration. I spent eight years in the city government of Somerville, Massachusetts, including stints as chief of staff to the mayor, as the director of the Office of Innovation & Analytics, and as budget manager. I then served as a senior consultant to state and local governments at Guidehouse, before accepting in 2021 a position as the Chief of Staff for Public Services Administration at the City of Ann Arbor.

Q. Are you familiar with the City's utility services and the City's interactions with private utilities that use the City's rights of way?

A. Yes. Those activities are largely within the public services area, so as part of my job I am

familiar with and often address issues related to use of the rights of way and the provision of water, wastewater, and stormwater utility services by the City of Ann Arbor, which involve underground infrastructure in the City's rights of way.

Q. Are you testifying today as an expert witness, fact witness, or both?

A. I am testifying in both capacities. I am an expert on public administration, including budgeting and execution of public infrastructure projects for city utilities. I am also presenting first-hand factual testimony related to specific interactions with DTE Electric Company ("DTE" or "the Company") in my current position.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the City's practices regarding coordination of utility work in the rights of way, my experiences regarding opportunities for coordination with DTE, and my role in recent efforts to replace DTE-owned streetlights in the City with LEDs.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibit:

Exhibit AA-12	Curriculum Vitae of Skye Stewart
Exhibit AA-13	Discovery Response MAUIDE-2.5
Exhibit AA-14	Page Avenue Project Estimated Savings

II. ANN ARBOR'S COORDINATION PRACTICES

Q. In your experience working for the City's Public Services Administration, is it typical that different public utility enterprises (e.g., water and wastewater) would coordinate infrastructure projects that involve digging in the rights-of-way (i.e., roads or sidewalks) in the City?

A. Yes. As part of the City's annual capital projects planning process, staff identify the infrastructure needs for each of the various public asset groups, including water, wastewater, and stormwater utility infrastructure as well as the roads, sidewalks, bike infrastructure, streetlights, and traffic signals, etc. The individual projects of each asset group are prioritized separately based on a variety of factors like system goals, asset condition, risk of failure, and consequence of failure. Projects are then programmed (or scheduled) in the Capital Improvements Plan ("CIP") based on prioritization rankings, budget availability, staff capacity, and coordination with other projects planned in the same area.

Q. In your experience, has the ability to coordinate with other projects in the same area altered the City's timeline for projects, such that they were done sooner or later to take advantage of that opportunity?

A. Yes.

Q. What kind of information does the City require an entity working in the right of way to supply?

A. To get a permit to excavate in the City's right of way, we require a drawing showing the location of planned work in relation to existing public utilities in the right of way. We also ask for other relevant information about the proposed work like the method of construction, the area of disturbance, and proof of insurance. Depending on the work, a Traffic Control permit may also be necessary.

Q. Why in your expert opinion does the City require right of way permits?

A. The City is responsible for the care and maintenance of nearly all public infrastructure in the public right of way including the drinking water distribution system and the sanitary

sewer collection system, both of which are critical to public health and safety. To limit the risk of damage to these critical utilities, the City requires any private entity to seek permission to occupy or excavate in the public right of way. We have had several problems with underground infrastructure being damaged by private utilities in Ann Arbor. The right of way permit attempts to prevent this from occurring by providing an opportunity for City staff to review proposed work and identify potential conflicts.

Q. Why does the City make efforts to coordinate utility work?

A. We believe that coordinating projects whenever possible is the most efficient use of staff time, which results in cost savings for taxpayers and ratepayers of the City's utility services. It also limits the disruption residents experience from the work. For example, one project manager could manage a water main replacement, a sanitary sewer replacement, and a road reconstruction within a single project. One of the biggest cost savings comes from avoiding digging up a road that has been recently resurfaced to do utility work. By coordinating through the CIP planning process, the City has mostly eliminated these instances.

Q. Does the City give DTE notice of plans to work in particular rights of way?

A. Yes. The City's CIP is a publicly available document that provides a six-year plan for public infrastructure projects. Additionally, as part of planning and designing specific projects in the public rights of way, City project managers notify the various utilities that may be impacted by the projects. Depending on the project, this notification could happen anywhere from six months to two years before construction begins. This is an opportunity for utilities to make any moves, upgrades, or needed repairs before the City resurfaces the road. Once the road has been resurfaced it goes on a Street Cut Moratorium

list for a period of time. This means private entities (including utilities) are generally prevented from re-opening the same area except when the work is necessary for public safety – for anywhere from 3 to 10 years.

Q. Is the City's CIP available on a publicly accessible website, such that DTE could access the CIP and see the City's planned projects for the next six years when undertaking its own capital project planning?

A. Yes.[1]

III. DTE'S COORDINATION PRACTICES WITH ANN ARBOR

Q. Has DTE ever proactively viewed the City's CIP and asked to coordinate a project such that its work is done at the same time as the City's work to reduce costs?

A. Not to my knowledge. In fact, DTE admitted in response to a discovery request by the Michigan Municipal Association for Utility Issues ("MAUI") that it does not routinely review municipal Capital Improvement Plans to identify projects that might be coordinated. Exhibit AA-13. I assume this applies to Ann Arbor's CIP.

Q. When does DTE notify the City of its planned projects in Ann Arbor?

A. Until recently there had been no predictable or established advanced notification process in place. In a discovery response to MAUI, the Company stated, "Once a DTE project is selected to move forward, our local government affairs team reaches out to the affected municipalities to notify them of work and identify potential coordination opportunities." Exhibit AA-13. In the last several months, DTE has been more communicative about their upcoming plans, sharing where they anticipate working in the upcoming year.

[1] The CIP is available at:
https://a2-mi.maps.arcgis.com/apps/dashboards/0fb6f6af7bc744d1a278f061bb3aa84b

Often, the way the City staff receives notice of a planned DTE project is through the Company's application for a right of way permit. Notice at this late stage of a project is not conducive to meaningful coordination or collaboration.

Q. Would there be a benefit to receiving notice earlier in the process of a planned DTE project?

A. Yes. With enough advanced notice, the City could evaluate whether it would be beneficial to advance or push out any City projects planned for the same area at the same time as DTE to avoid the cost and disruption of digging up and restoring the right of way multiple times.

Q. Do you have any examples that demonstrate how much DTE could save by coordinating projects that involve digging up the right of way?

A. Yes. I have an example that involves DTE's sister company, DTE Gas Company ("DTE Gas"), which is the provider of fossil gas in Ann Arbor.

It was discovered during the City's franchise negotiations with DTE Gas that DTE Gas had a project planned in the Page Avenue area, where the City was in the process of designing and scoping work for a street reconstruction and sidewalk gap project. The City informed DTE Gas that if the Company couldn't move its project timeline up to complete it before the City resurfaced the right of way, it would not be able to obtain a right of way permit for excavation because roads in the area would be subject to our Street Cut Moratorium. Moreover, if DTE Gas were able to complete its project while the City had Page Avenue open, DTE Gas would benefit from the City covering the cost of resurfacing the right of way.

The City calculated the estimated savings to DTE Gas of not having to pay resurfacing

costs to be $70,459 (approximately 14% of an assumed $500,000 gas main project cost). Exhibit AA-14.

Q. Would DTE Electric potentially be able to achieve similar savings through coordination with the City as you identify for DTE Gas in the Page Avenue project?

A. Yes, it is possible. The Page Avenue project savings are largely attributable to the City covering the costs of resurfacing the right of way, so similar savings are potentially available for DTE Electric projects that involve underground wiring, including many projects involving underground work for streetlighting.

Q. Have you seen recent improvements in communications regarding infrastructure from DTE?

A. Yes. Both DTE Gas and DTE Electric have reached out to schedule meetings with project management staff about upcoming projects. Unfortunately, most of these projects are in the 0 to 2 year time horizon which limits how much true coordination can happen. However, DTE has been able to advance some work this construction season to align with some ongoing City infrastructure projects. City staff are encouraged by DTE's recent willingness to share information about upcoming projects much farther in advance and we hope that in the future these efforts continue and evolve to a regular process that looks to longer time horizons to allow for true coordination.

IV. STREETLIGHTING SELECTION

Q. Have you been involved in the process by which Ann Arbor is seeking to convert its remaining DTE-owned HID streetlights to LEDs with grant dollars?

A. Yes, in my role I have been part of the team involved in that effort.

Q. Do you agree with the testimony of Witness Naheedy regarding that process,

including several potential sources of increased costs that DTE said would result from the City choosing a light with a lower wattage and warmer color temperature than DTE's standard offering?

A. Yes.

Q. Does this conclude your direct testimony?

A. Yes.

Q. Do you swear under penalty of perjury that the statements above are true to the best of your knowledge, information, and belief?

A. Yes.

Skye Stewart

Skye Stewart

MS. BRADER: I move to bind into the record the prefiled Direct Testimony of Dr. Melissa Stults, consisting of a cover page and 33 pages of questions and answers. With that testimony, she sponsors 21 exhibits, designated sequentially AA-15 through AA-35, which I move to admit into the record.

JUDGE WALLACE: O.K. Is there any objection to binding in the testimony of Dr. Stults?

Hearing none, the testimony is bound in.

Is there any objection to the admission of Exhibits AA-15 through AA-35?

Hearing none, those exhibits are admitted.

(Testimony bound in.)

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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.	U-21534

DIRECT TESTIMONY OF DR. MELISSA STULTS

ON BEHALF OF

THE CITY OF ANN ARBOR

July 26, 2024

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Dr. Melissa Stults. I am the Sustainability and Innovations Director for the City of Ann Arbor, Michigan. My office is located at 301 E. Huron Street, Ann Arbor, MI 48104.

Q. Please describe your educational background and professional experience.

A. I hold a dual doctoral degree of urban resilience from the University of Michigan. This degree is from Urban and Regional Planning and from the former School of Natural Resources and the Environment, now known as the School for the Environment and Sustainability ("SEAS"). I also hold a master's degree in Climate and Society from Columbia University and bachelor's degrees in Marine Biology and Environmental Sciences from the University of New England.

Professionally, I have spent the last 20 years working directly with local and regional governments, as well as indigenous populations, to advance climate and sustainability actions. This has included work in nonprofits, for profits, academic institutions, philanthropic organizations, and local government. In this work, I have focused on translating complex scientific information into useful, usable, and understandable pieces of knowledge that can inform decision-making across scales (i.e., local, regional, statewide) and sectors (i.e., built, natural, social, cultural, economic). I have been the City of Ann Arbor's head of Sustainability and Innovations for six years but have worked on sustainability and climate-related activities in Ann Arbor since moving to the City in 2012.

Q. On whose behalf are you submitting your testimony in this proceeding?

A. My testimony is on behalf of the City of Ann Arbor ("Ann Arbor" or "the City").

Q. Have you previously testified before this Commission or as an expert in other proceedings?

A. Yes. I have provided testimony on behalf of Ann Arbor in Case Nos. U-20471, U-20836, U-21172, U-21297, U-21384, and U-21291.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss and provide context for the following recommendations:

1) The Commission should take DTE Electric Company's ("DTE" or "the Company") performance into consideration when setting the Company's rate of return on equity ("ROE"), considering DTE's continued requests for significant rate increases with no corresponding improvement to reliability.
2) The Commission should deny DTE's request to increase its ROE because the Company has a history of requesting ROEs that are unreasonably high.
3) The Commission should deny the Company's outage credit proposal.
4) The Commission should deny DTE's proposed Storm Recovery Cost Sharing Mechanism.
5) The Commission should disallow $39.232 million of the Company's incentive compensation expense.
6) The Commission should find that DTE has not fully complied with its directive from Case No. U-21297 regarding coordination with local governments.
7) The Commission should ensure that costs to increase the load capacity at a

development site that is served by a 4.8kV system are no more than they would be if the site were served by a 13.2kV system.

8) The Commission should not permit DTE to purposefully fall behind its pole and pole-top inspection cycle.

9) The Commission should require DTE to raise the income-qualified threshold for Home Charger Rebates.

10) The Commission should disallow the residential home generator pilot and all its associated costs.

11) The Commission should require DTE to expand its strategic undergrounding pilot projects beyond the City of Detroit and require DTE to be more transparent regarding its selection process for such pilot projects.

12) The Commission should require the Company to pay a credit to communities who proactively converted their streetlights to LEDs and paid a CIAC up front.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit AA-15	Curriculum Vitae of Dr. Melissa Stults
Exhibit AA-16	U.S. Energy Information Administration Data: Average Price by State
Exhibit AA-17	Excerpt of Direct Testimony of Dr. Bente Villadsen (Case No. U-21297)
Exhibit AA-18	Fitch Ratings Rating Action Commentary (Mar. 21, 2024)
Exhibit AA-19	Excerpt of Direct Testimony of Dr. Bente Villadsen (Case No. U-20836)
Exhibit AA-20	Fitch Ratings Rating Action Commentary (Feb. 27, 2023)

Exhibit AA-21	Fitch Ratings Screenshot Showing Ratings History
Exhibit AA-22	DTE Business Update, June 18, 2024
Exhibit AA-23	DTE Business Update, April 2-3, 2024
Exhibit AA-24	DTE Business Update, Dec. 8, 2023
Exhibit AA-25	DTE Business Update, Apr. 3-4, 2023
Exhibit AA-26	DTE Business Update, Aug. 11, 2020
Exhibit AA-27	DTE Year-end Earnings Conference Call, Feb. 23, 2023
Exhibit AA-28	Discovery Response AADE-1.1
Exhibit AA-29	Discovery Response AADE-1.2
Exhibit AA-30	Discovery Response AADE-3.2
Exhibit AA-31	Discovery Response AADE-3.1
Exhibit AA-32	Discovery Response MNSCDE-13.10b
Exhibit AA-33	Discovery Response MNSCDE-13.10a
Exhibit AA-34	Excerpt of CPUC Root Cause Analyses
Exhibit AA-35	DTE 2022 Sustainability Report

II. CUSTOMERS SHOULD NOT BE EXPECTED TO CONTINUE SUPPORTING DTE'S INVESTMENTS THROUGH UNREASONABLE BILL INCREASES WITH NO CORRESPONDING IMPROVEMENT IN RELIABILITY

Q. What is the revenue deficiency the Company is requesting in this case?

A. Less than four months after receiving approval to implement rates that increased its annual revenues by over $368 million, the Company is again before the Commission requesting a rate increase that would add an additional $456.4 million in annual

revenues.[1] Since 2017, the Commission has authorized six rate increases totaling over $1.1 billion in increased annual revenues.[2] If the Commission authorizes the Company's requested amount in this case, that would mean an increase of $1.566 billion in just eight years, which averages out to almost $200 million per year. That is simply not sustainable for ratepayers.

Q. On pages 5-6 of her direct testimony, Company witness Adella F. Crozier states that DTE plans to invest approximately $9 billion in the grid and $7 billion in cleaner generation between 2024 and 2028, and that "we believe these investments will generate significant benefits and value to our customers." Do you believe customers have seen significant benefits and value from the $1.1 billion increase in DTE's annual revenues over the past seven years?

A. No. Customers continue to pay more and more for service that is not improving. The Company's All Weather SAIDI was 1,063 minutes in 2017 and 1,542 minutes in 2023. The average All Weather SAIDI for the three years from 2018 through 2020 was 448 minutes, whereas the average for the three years from 2021 through 2023 was 1,018 minutes – over *double* the preceding three-year period.[3]

The Company's All Weather SAIFI was 1.39 in 2017 and 1.72 in 2023. The average All

[1] Application, p. 2.
[2] Case No. U-18014 authorized an increase in annual revenues of $184,336,000 (Order, Jan. 31, 2017). Case No. U-18255 authorized an increase in annual revenues of $65,239,000 (Order, Apr. 18, 2018). Case No. 20162 authorized an increase in annual revenues of $273,334,000 (Order, May 2, 2019). Case No. U-20561 authorized an increase in annual revenues of $188,285,000 (Order, May 8, 2020). Case No. U-20836 authorized an increase in annual revenues of $30,557,000 (Order, Nov. 18, 2022). Case No. U-21297 authorized an increase in annual revenues of $368,115,000 (Order, Dec. 1, 2023).
[3] *See*, Kryscynski, p. 19, Figure 2.

Weather SAIFI for the three years from 2018 through 2020 was 1.34, whereas the average for the three years from 2021 through 2023 was 1.52 – over a 13% increase from the previous three-year period.[4] The Commission should not be approving large investments until the audit of DTE's distribution system is complete, to confirm that the Company's projected capital investments will make a measurable impact on reliability.

Q. On page 8 of Company witness Crozier's direct testimony, she states that according to the publicly available Interruption Cost Estimator Calculator, "the Company's forecasted reliability improvements could generate more than $15 billion of positive economic impacts." What is your reaction to that testimony?

A. According to the previous question, the Company is planning to invest a total of $16 billion between 2024 and 2028, so an estimated $15 billion in positive economic impacts will result in a net loss of $1 billion. That does not seem worth the investment.

Q. On page 16 of DTE witness Crozier's direct testimony, there is a figure (Figure 8) showing the 2023 Average Residential Electric Bill in each state compared to DTE. This figure shows that DTE's average residential bills are below the national average. Do you have any concerns with this figure or the implications one may draw from it?

A. Yes. Presenting the data in this way without context is misleading. It seems Ms. Crozier is using this figure to demonstrate that DTE's rates are reasonable because its customers are spending less on electricity on average than their peers. However, this figure does not account for the amount of electricity used in each state, so it does not accurately reflect

[4] *See*, Kryscynski, p. 20, Figure 4.

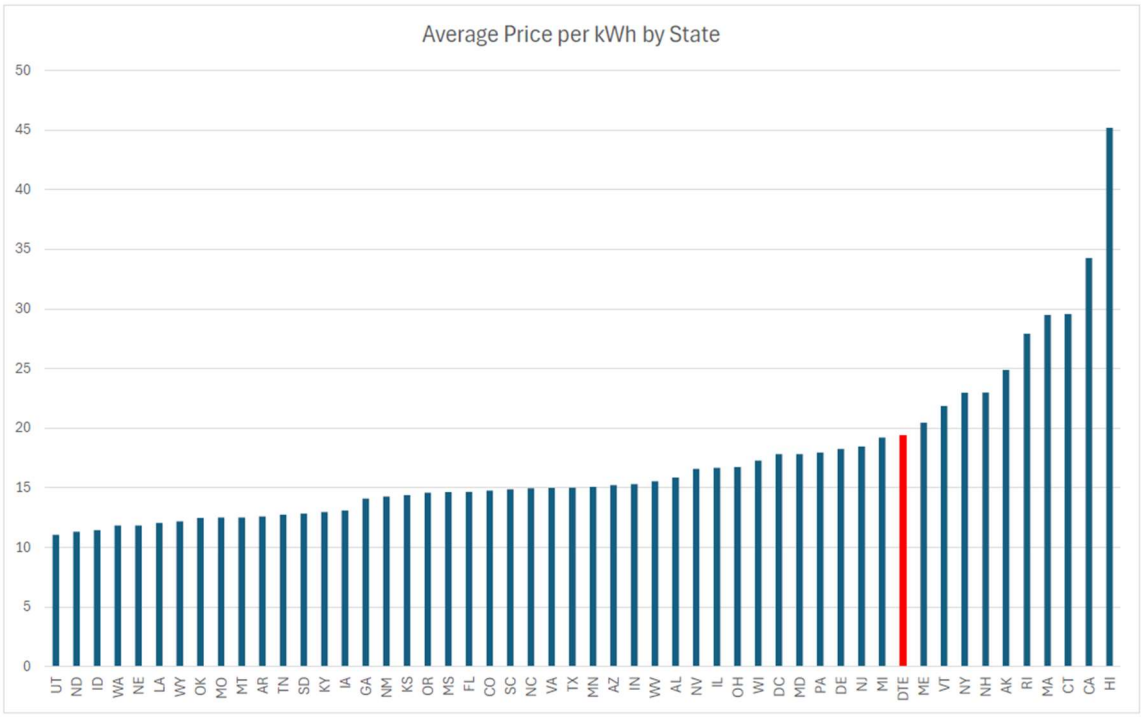
the rate each states' residents pay for electricity on a unit basis. Residents in many of the states included in this figure use electricity (rather than gas) for space heating, which means they are using more electricity and would be expected to receive higher electric bills.

Q. What would be a more accurate comparison regarding the price of electricity for DTE's customers versus customers of other utilities?

A. A more accurate comparison would show the cost of electricity per unit (i.e., kWh). As you can see from Figure 1[5] below, when the data is compared in this way, it's apparent that DTE's customers are actually paying some of the highest per unit rates in the nation. DTE ranks 11th highest in price per kWh when compared to the 50 states and the District of Columbia, placing it in the top quartile. DTE also has higher average rates than all twelve states in the East North Central and West North Central regions (i.e., the entire Midwest). Exhibit AA-16.

[5] Figure 1 was created with data from the U.S. Energy Information Administration reflecting the average price of electricity by state in April 2024. Exhibit AA-16. DTE's average price per kWh was determined using the median present monthly bill ($136.06 / 700 kWh = $0.194) in Attachment 3 to DTE's Application.

Figure 1: Average Price (cents/kWh) by State - April 2024



Q. What is your recommendation based on DTE's continued poor reliability and above average price?

A. I recommend the Commission hold DTE accountable and put an end to its annual attempt to squeeze more and more out of ratepayers for the promise of improved reliability – a promise that is never realized. The Commission has the authority to consider the value of service DTE provides its consumers when setting rates.[6] In the order in the last rate case, the Commission said it "will continue to seek opportunities to better tie DTE Electric's financial performance to the outcomes experienced by its customers through the ongoing Financial Incentives and Disincentives Workgroup."[7] I recommend the Commission use

[6] MCL 460.557(2).
[7] Order, p. 186, Case No. U-21297 (Dec. 1, 2023).

its authority to consider the value of DTE's service to better tie DTE's financial performance to its customers' experience in this case – through denying a large portion of DTE's requested rate increase and taking its performance into consideration when determining an appropriate rate of return on equity ("ROE"). This will better align DTE's "premium" returns with how it would fare in the market if it competed with other utilities, who provide a more reliable product at a lower rate.

III. DTE'S REQUESTED RETURN ON EQUITY IS UNREASONABLY HIGH

Q. Have you reviewed publicly available statements by Fitch Ratings ("Fitch"), a financial ratings agency, stating its views over time about the current and historical MPSC-approved ROE for DTE?

A. Yes. I have reviewed statements Fitch made regarding the approved ROEs and the Long-Term Issuer Default Rating of the Company.

Q. What rate of return on equity ("ROE") is DTE seeking in this case?

A. DTE is requesting an ROE of 10.5%. Application, p. 4. This is an increase of 60 basis points from the currently authorized ROE of 9.9%, which was approved in Case No. U-21297.

Q. What does DTE witness Dr. Bente Villadsen state regarding the Company's requested ROE in this case?

A. Dr. Villadsen recommends that DTE be allowed to earn its requested ROE of 10.5%, and states that this recommendation is "conservative and a modest move towards today's indicated cost of equity."[8] Her recommendation is based in part on her opinion that DTE has a "higher business risk than the comparable electric utilities," because, among other

[8] Revised Direct Testimony of Villadsen, p. 7.

things, the Company has a "higher than average need for infrastructure investments."[9]

Q. Has Dr. Villadsen supported the Company's recommended ROE in any other general rate cases?

A. Yes, Dr. Villadsen supported DTE's recommended ROE in Case Nos. U-20561, U-20836, and U-21297.

Q. What was Dr. Villadsen's recommended ROE in Case No. U-21297?

A. Dr. Villadsen recommended an ROE of 10.25%, in part because she found DTE to have "higher business risk than the comparable electric utilities." Exhibit AA-17.

Q. What ROE did the Commission ultimately authorize in Case No. U-21297?

A. The Commission authorized an ROE of 9.9%, finding DTE's requested ROE of 10.25% to be "excessive and unsupported on [the] record," and emphasizing that "adjusting for financial risk or applying financial leverage adjustments is not appropriate." [10]

Q. Did Fitch make any statements following the Commission's decision in Case U-21297 regarding the authorized ROE?

A. Yes. Fitch stated on March 21, 2024 that the authorized ROE of 9.9% "compares favorably with industry averages," and "the rate order issued in December is credit-supportive and reflects a constructive regulatory environment in Michigan." *See*, Exhibit AA-18.

Q. What was Dr. Villadsen's recommended ROE in Case No. U-20836?

A. Dr. Villadsen recommended an ROE of 10.25%, in part due to DTE's "higher business risk than the electric sample group," and stated that this was a "conservative estimate."

[9] *Id.* at 6-7.
[10] Order, p. 186, Case No. U-21297 (Dec. 1, 2023).

Exhibit AA-19.

Q. What ROE did the Commission ultimately authorize in Case No. U-20836?

A. The Commission authorized an ROE of 9.9%, finding DTE's requested ROE of 10.25% to be "excessive and unsupported on [the] record," and noting that DTE "overstates its business risk."[11]

Q. Did Fitch make any statements following the Commission's decision in the Case U-20836 regarding the authorized ROE?

A. Yes. In February 2023, Fitch stated DTE's authorized ROE of 9.9% "compares favorably with industry averages." Exhibit AA-20.

Q. Did the Commission's approval of authorized ROEs lower than Dr. Villadsen's recommended ROEs in the Company's past two general rate cases negatively impact Fitch's Long-Term Issuer Default Rating of DTE?

A. No. Despite the Commission's authorization of ROEs noticeably lower than those recommended by Dr. Villadsen, the Company has maintained its Long-Term Issuer Default Rating of A- since well before the Commission's November 2022 order in U-20836. Exhibit AA-21.

Q. Have you reviewed any publicly available statements made by the Company to its investors from the time period contemporaneous with the past two rate cases?

A. Yes. I have reviewed DTE's Business Updates from the past few years, all of which are publicly available on the Company's website.

Q. In those Business Updates, did the Company make any statements to its investors

[11] Order, p. 241-43, Case No. U-20836 (Nov. 18, 2022).

regarding shareholder returns, risk of investment, or the regulatory environment in Michigan?

A. Yes. Some examples include:

- In June 2024, DTE indicated one of the ways it delivers best-in-class results for investors is by "Delivering premium shareholder returns." Exhibit AA-22.
- In April 2024, DTE highlighted that one of the ways it is "Delivering premium shareholder returns," is by "Increas[ing] 5-year utility capital investment by $2 billion over previous plan," and then on the next page claimed to be "maintaining affordability." Exhibit AA-23.
- On December 8, 2023 (one week after the Commission authorized an ROE 35 basis below DTE's requested ROE in Case No. U-21297), DTE stated the "Constructive rate case order supports customer-focused investments," and its "Strong balance sheet and solid investment-grade credit profile support capital investment." Exhibit AA-24.
- In April 2023, DTE noted the Company was able to deliver "premium shareholder returns," while "maintaining solid investment-grade credit ratings" and "providing a healthy dividend." Exhibit AA-25, p. 4, 16.

Q. In your review, did you find any instances of the Company reporting to shareholders that it was negatively impacted by the Commission's failure to approve the ROE recommended by its witness?

A. No.

Q. With the benefit of hindsight, do you think the testimony provided by Dr. Villadsen recommending an ROE of 10.25% in the Company's past two general rate cases was reasonable?

A. No. As DTE has itself stated, the Company has been able to consistently deliver "premium" returns to shareholders and maintain a positive and stable credit rating, despite having an authorized ROE substantially lower than Dr. Villadsen claimed was necessary to continue attracting equity investors.

Q. What does this review of the history of DTE's past testimony regarding ROE suggest to you about Dr. Villadsen's testimony in this case?

A. As the review above demonstrates, Dr. Villadsen has a pattern of recommending an above-average ROE based on a claim that the Company is a higher-than-average business risk, despite consistently being proven wrong by the review of rating agencies, the Company's long history of earning its authorized ROE, and its delivery of "premium" shareholder returns even when an ROE significantly below her recommendation is authorized by the Commission. To me, this history is proof that an ROE lower than the one recommended by Dr. Villadsen would be sufficient to allow the Company to mitigate risk and provide an opportunity for reasonable shareholder returns. Therefore, Dr. Villadsen's testimony should be given little weight, and the Commission should reject her recommendation to increase the Company's ROE. Instead, I believe the Commission should strongly consider a lower ROE than previously granted to send a meaningful notice to DTE that until it starts improving reliability, it will not be able to earn as high a rate of return.

IV. DTE SHOULD NOT BE ABLE TO RECOVER OUTAGE CREDITS THROUGH RATES

Q. What is your understanding of DTE's outage credit recovery proposal?

A. DTE is proposing a mechanism that would allow it to recover credits it has paid to

customers as a result of outages that either exceeded the outage duration limits or the outage frequency limits outlined in the Service Quality and Reliability Standards for Electric Distribution Systems ("Service Quality Standards")[12] in certain enumerated situations in subsequent rate cases.

Q. What are the situations under which DTE believes it should be able to recover an outage credit?

A. DTE is proposing that it be able to recover credits paid for exceeding the outage duration limit if the underlying outage was caused by (1) the transmission operator or another utility, (2) public interference, or (3) animal interference, and to recover credits paid for exceeding the outage frequency limit for any of the previously listed reasons, in addition to outages caused by (1) ice, (2) lightning, (3) wind, or (4) other weather.[13]

Q. Do you believe this proposal is reasonable?

A. No.

Q. What do you find unreasonable about this proposal?

A. It is particularly unreasonable that DTE is asking to recover credits for outages caused by weather or animal interference, which a better maintained grid would withstand, considering the Company is planning to spend billions of dollars (and has already spent a significant amount of ratepayer money) to allegedly improve the grid. The Company earns a return – funded by the ratepayers – on these investments in the grid. In return, ratepayers should get a more reliable and resilient grid. The Commission has determined that when that grid fails, and an outage exceeds the outage duration or frequency limits

[12] R 460.744 and R 460.745.
[13] Crozier, p. 32-33; list of outage causes (cleaned up).

set forth in the Service Quality Standards, the Company must pay a credit for its failure to meet its end of the bargain. DTE should not get to go back to the ratepayers who have already paid for the investment in the grid, plus a return on that investment, to try to recover credits paid for the grid's failure.

Moreover, it is unreasonable for the Company to request recovery of outage credits as an attempt to make itself whole for "outages caused by events outside DTE Electric's control,"[14] when the outage credits they are attempting to claw back from ratepayers do not come close to making whole the customers who were without power long enough or frequently enough to receive an outage credit. Customers who go without power long enough to receive a paltry $38 outage credit are likely throwing away hundreds of dollars in perishable food alone, not to mention the cost of purchasing replacement food, lost productivity, possible property damage, and alternative housing in cases of extreme weather. It is insulting that DTE has even spent time on this issue. The Company's resources should be spent on efforts to improve its customers' experience, not on trying to figure out a way to increase rates so that DTE is never actually financially accountable for a portion of the credits the Commission has determined it owes under the Service Quality Standards.

Q. Are there any circumstances under which the Company's recovery of an outage credit through rates may be appropriate?

A. Possibly. But those circumstances would be extremely limited and should be reviewed on a case-by-case basis. In 2022, the Commission stated, "it is reasonable that the company

[14] Crozier, p. 31.

have the ability to recover outage credits when the outage was caused by customer negligence or the transmission system operator, among other limited circumstances."[15] I agree that if the Company paid an outage credit for an outage that is determined to be due to customer negligence, it may be reasonable for the Company to recover that credit. However, attempting to recover a $38 credit does not seem like the best use of the Company's time, and as indicated above, the outage credit amount is comically small in comparison to the actual costs a customer incurs as a result of an outage, so perhaps the Company should consider the rare cases where an outage may have been due to a customer's negligence as a cost of doing business.

Q. What is your recommendation regarding the Company's outage credit proposal?

A. The Commission should deny the Company's outage credit proposal. It is an unreasonable attempt by the Company to squeeze more out of already overly burdened ratepayers for failures of the equipment that the ratepayers are already paying for through their rates and on which shareholders continue to earn a profit.

V. DTE'S STORM RESTORATION COST SHARING MECHANISM SHOULD NOT BE AUTHORIZED

Q. What is your understanding of the Company's proposed Storm Restoration Cost Sharing Mechanism?

A. The Company is proposing a Storm Restoration Cost Sharing Mechanism ("SRCSM") that would allow it to include projected storm restoration operation and maintenance ("O&M") costs in rates and then "share" the difference between the projected costs and the actual costs with ratepayers. It would do this by returning half of the difference to

[15] Order, p. 367, Case No. U-20863 (Nov. 18, 2022).

customers if actual costs are less than projected costs (i.e., recording a regulatory liability) and by recovering half of the difference from customers if actual costs are more than projected costs (i.e., recording a regulatory asset). The resulting regulatory asset or liability from each year would be included in a subsequent rate case.

Q. Is the Company's proposed SRCSM reasonable in design or amount?

A. No.

Q. What do you find unreasonable about the proposed SRCSM design?

A. I see several problems with the proposed SRCSM's design.

First, it creates problematic incentives for the Company, including motivating the Company to play a shell game with capital recovery for repairs, because repairs done before a storm or after a storm would be recovered differently from those that took place immediately after a storm. It essentially gives the Company two bites at recovery: one through the SRCSM, and one through rate recovery. If the Company "puts off" a repair that could be linked to storm recovery but rolls the truck again two weeks later, does that count against the SRCSM or other accounts? Or if something can be classified as storm recovery that would normally be a standard repair, the Company may be incentivized to do that using overtime during a year where storms are relatively mild. If the need for a restoration is directly attributable to the Company's failure to do proper maintenance on infrastructure, will that receive the same level of scrutiny on revenue requirements in the next rate case if recovered through the SRCSM as it would otherwise?

The SRCSM would also reward the Company for projecting very high estimates of storm restoration costs, so it appears to "underspend" its target. Overestimations would allow the Company to recover some monies that were never spent and thus would normally not

be properly included in rate recovery. The Company will get to keep half of every dollar it underspends on storm restoration, which incentivizes the Company to project very high storm damage costs. That is much easier to do if the system's maintenance is substandard, which gives the Company an additional incentive (beyond the normal ROE multiplier for capital vs. cost recovery for non-capital) to underspend on maintenance. Thus, DTE will be motivated to spend as little on storm restoration as possible to maximize the amount of money it can make for doing nothing.

Finally, it creates a situation in which ratepayers will be paying for investments to improve the resiliency of the grid (as well as a return on those investments), which should result in lower storm restoration costs, and then when those investments are successful in reducing such costs, half of the benefit of reduced storm restoration costs (i.e., reduced rates) will not flow to the ratepayers. As I explained in my testimony in the last rate case, DTE has told investors that one of the ways it manages to deliver premium returns is to have its O&M spend rise at half the rate of other utilities, and one of the ways it was planning to "ensure a successful 2023" was through O&M reductions including deferring maintenance. Exhibit AA-26; Exhibit AA-27. The Company's history of underspending on O&M is one of the reasons DTE delivers reliability that is much worse that other utilities. The way the SCRSM as proposed is set up would allow the Company to keep half of the savings that result from coming up to normal maintenance standards. It would be unreasonable for the Company not to pass these savings on to the ratepayers who funded the more resilient grid and suffered due to DTE's decisions to underspend on O&M for more than a decade.

Q. Has DTE been able to maintain its 5-year tree trimming cycle over the past decade?

A. No. The Company departed from its prior practice of maintaining a five-year trim cycle in 2013,[16] and it has been playing a game of catch-up ever since through a series of "enhancements" to its tree trimming program and surge funding requests to address its (at points, "three to four-year") backlog of untrimmed circuits.[17]

Q. In your view does the failure to maintain its tree trimming cycle increase storm response costs?

A. Yes, as Ann Arbor witness Tiffany Giacobazzi explains, failure to meet tree trimming goals increases reactive incidents markedly.

Q. Is the amount that storm costs have been raised by improper maintenance and falling behind on tree trimming quantifiable?

A. Yes. Historically, two-thirds of the time DTE customers spend without power is due to outages caused by tree interference.[18] As Ann Arbor witness Tiffany Giacobazzi discusses in her testimony, Ann Arbor street tree data indicates that trees trimmed less than 5 years ago require less than half the level of reactive maintenance (branches down, damaged) as those that were trimmed five or more years ago. Therefore, if the Commission approves the SRCSM, it should reduce the proposed SRCSM amount for each year using the following formula:

Step 1: Multiply the total proposed storm recovery costs by 2/3rds to account for those due to tree damage;

Step 2: Multiply the amount from Step 1 by the percentage of trees in DTE's

[16] PFD, p. 145-46, Case No. U-20162 (Mar. 6, 2019).
[17] Order, p. 75, Case No. U-20162 (May 2, 2019).
[18] Steudle, p. 5.

vegetation plan that were last trimmed 5 or more years ago;

Step 3: Divide the product from Step 2 by 2 to reflect the amount of reactive maintenance that would have been avoided; and

Step 4: Subtract the result from Step 3 from the proposed SRCSM amount. The resulting difference should be the approved SRCSM amount.

Q. What is your recommendation regarding the proposed SRCSM?

A. The Commission should deny the Company's proposed SRCSM due to its fundamental design flaws. Alternatively, if the Commission approves the SRCSM, it should adjust the amount to ensure the Company cannot escape the consequences of its long practice of deliberately restricting O&M and failing to prioritize tree trimming.

VI. THE COMMISSION SHOULD DISALLOW $39.232 MILLION OF DTE'S INCENTIVE COMPENSATION EXPENSE

Q. What is DTE requesting for incentive compensation expense?

A. DTE is requesting a total incentive compensation expense of $59.504 million. According to Table 3 on page 62 of DTE witness Michael S. Cooper's direct testimony, this amount is made up of $39.232 million for financial measures and $20.271 million for operating measures.

Q. Has the Commission provided any guidance on whether incentive compensation can be included in rates?

A. Yes. In fact, earlier this month, the Commission spent several pages on this issue in Indiana Michigan Power Company's ("I&M") most recent rate case.[19] The Commission began its discussion of the issue by stating, "for nearly two decades, it has disallowed

[19] Order, p. 84-87, Case No. U-21461 (July 2, 2024).

financially based incentive compensation in utility rates."[20] It went on to note "the Commission's long history of unequivocally disallowing financially based incentive compensation, whether it be an O&M expense or capital expenditure."[21] The Commission disallowed I&M's financially based incentive expenditures, finding them to be "unreasonable and imprudent because they are inextricably connected to earnings and cash flow and disproportionately benefit shareholders and should not be paid for by ratepayers."[22]

This is clear guidance from the Commission that ratepayers should not be paying for financially based incentive compensation.

Q. Are there any portions of the Company's incentive compensation expense that are particularly problematic?

A. Yes. The Company's Long-Term Incentive Program ("LTIP"), which accounts for $20.408 million of DTE's request for incentive compensation, is especially problematic. The only two measures for the LTIP are the total return to shareholders and the three-year operating earnings per share, and even DTE has not estimated a benefit to shareholders from the LTIP. *See*, Exhibit A-21, Schedule K6. Thus, it is clear that the expense of LTIP should not be borne by ratepayers.

Q. What is your recommendation regarding the Company's request for $59.504 million in incentive compensation expense?

A. The Commission should disallow $39.232 million of the Company's incentive

[20] *Id.* at 84.
[21] *Id.* at 86.
[22] *Id.* at 87.

compensation expense because it is for financial measures that are inextricably connected to earnings and cash flow and ultimately benefit DTE's shareholders, not its ratepayers.

VII. DTE'S FAILURE TO COMPLY WITH THE COMMISSION'S DIRECTIVE REGARDING COORDINATION IN CASE NO. U-21297

Q. Did the Commission's order in Case No. U-21297 include any directives to DTE regarding coordination with local governments?

A. Yes. The Commission's order stated, "in its next rate case, DTE Electric shall include a demonstration of its efforts to improve communication and coordination with local governments regarding construction activities."[23]

Q. Has DTE included a demonstration of such efforts in this rate case?

A. No. DTE included approximately one single page of testimony regarding its coordination with local governments, and half of that page was an explanation of what the Company currently does (and has done in the past) to communicate its already-planned projects to local governments.[24] The Company's "efforts to improve communication and coordination" include "working to improve the frequency of updates to municipalities and garnering feedback to determine their preferred methods of receiving these updates."[25]

While Ann Arbor has seen recent improvements in communications as Ann Arbor witness Skye Stewart describes, those discussions originated in gas franchise discussions, and I would defer to Michigan Municipal Association for Utilities Issues ("MAUI") witness Bunch on whether other local governments have seen similar improvements.

[23] Dec. 1, 2023 Order, Case No. U-21297, p. 361.
[24] Kryscynski, p. 101-02
[25] *Id.* at 102.

While I welcome improvements in DTE's communications with Ann Arbor, real cost savings for the City will come when the Company actually coordinates with all local governments in the planning of projects, and not just the only municipality that both has a franchise expiring with a sister utility and chooses to intervene on its own in rate cases. I believe DTE must do more to comply with the Commission's directive regarding coordination.

Q. What do you think was the purpose of the Commission's directive regarding coordination in Case No. U-21297?

A. The purpose of the Commission's directive was for DTE to include local governments in the planning and coordination of projects in their early stages in an effort to identify cost savings and efficiencies, not merely to communicate DTE's pre-planned projects to communities.

Q. Ann Arbor witness Skye Stewart shares an example of cost savings from coordination of a DTE Gas Company project with the City. Do you have any suggestions for coordination opportunities the Company could seek?

A. Yes. Though not with local governments, the Company has a low-cost opportunity to coordinate with DTE Gas Company, due to the fact that the work of both companies brings them into contact with trees and other vegetation.

In discovery, DTE admitted that its "tree trimmers are not trained to identify signs of vegetation damage due to gas leaks," and thus do not report signs of vegetation damage due to gas leaks that they observe while performing work related to tree trimming and vegetation clearing. Exhibits AA-28 and AA-29.

As Ann Arbor witness Tiffany Giacobazzi discusses in her testimony, trees damaged by

gas leaks often die from the top down, leaving dead branches at the crown. These high branches are then more likely to break loose and impact a power line than lower, healthy branches.

Thus, two-way communication between DTE Electric and DTE Gas regarding tree and vegetation health would be a low-cost way for the companies to coordinate and avoid possible damage to power lines and/or complications due to gas leaks. DTE Electric could report to DTE Gas when its tree trimming crews come across vegetation that shows signs of a gas leak, and DTE Gas could report to DTE Electric when it repairs a gas leak and discovers a nearby tree with damage that needs trimming to avoid possible electrical damage.

VIII. UNFAIR CIAC PRACTICES FOR PROJECTS THAT INVOLVE INCREASING ELECTRIC LOAD CAPACITY

Q. Has the City received complaints from developers regarding the cost of upgrading the electrical infrastructure for projects in Ann Arbor?

A. Yes. The City has received complaints regarding the wide variation in cost estimates for extending electrical service and/or expanding electrical capacity for development projects depending on their location.

Q. Are you aware of the reason for the wide variation in cost estimates?

A. As indicated in a DTE discovery response, "New development projects have a wide range of variables from site-to-site and project type." Exhibit AA-30. This likely accounts for some variation in cost estimates from site to site, however, I am concerned that the reason developers are facing large cost estimates in Ann Arbor is due to the fact that much of the City is still served by a 4.8kV system, and thus generally does not have as

much capacity as areas served by 13.2kV systems.

Q. Were you able to confirm this?

A. No. When DTE was asked pointed discovery questions on this issue, the Company declined to give a meaningful response. *See*, Exhibit AA-31 ("The Company has not performed an analysis on hypothetical examples of development projects that involve increasing the load capacity for a site.") and Exhibit AA-30 ("The Company has not performed the analysis as requested.").

However, in response to another intervenor's discovery request, the Company stated. "When compared to 4.8kV, 13.2kV equipment has 2.5 times the power capacity. This results in less equipment in the field and an overall less complex system to operate. The lower equipment and operating costs make 13.2kV a more cost effective alternative to the 4.8kV system." Exhibit AA-32.

This suggests that, as a general rule of thumb, it would indeed be more costly to upgrade the electric infrastructure of a site to serve a certain load capacity if that site were served by a 4.8kV system than it would be to upgrade another site to serve that same load capacity if that other site were served by a 13.2kV system.

Q. If it does cost more to upgrade electrical infrastructure to increase the load capacity at a site served by a 4.8kV system than it would to serve the same load capacity at a site served by a 13.2kV system, is it fair to pass that cost on to the developer as a contribution in aid of construction ("CIAC")?

A. No. DTE has stated that it plans to convert all 4.8kV grid infrastructure to a higher

voltage over time.[26] In discovery, DTE stated that the distribution voltage it plans to convert to is 13.2kV. Exhibit AA-33. A developer should not have to pay more for a project because it is sited in an area that is still served by a 4.8kV system. It is unfair for a developer to be required to cover these costs that (a) it would not have to pay if the project were sited in a newer or upgraded community with a 13.2kV system, and (b) the Company would have covered eventually when it converted the grid at that location.

Q. What do you recommend regarding the CIAC for projects that involve increasing the electric load capacity at a site that is still served by a 4.8kV system?

A. I recommend the CIAC be no more than it would be if the site were served by a 13.2kV system – that is the Company should cover the costs for increasing the capacity in the area by 2.5 times before any CIAC is charged to the developer for increased capacity. A developer should not have to pay the cost differential necessary to increase the capacity from that of a 4.8kV system to that of a 13.2kV system. Requiring the developer to cover this cost differential is unreasonable because it unfairly favors projects in newer communities and discourages increasing development density in older cities like Ann Arbor, Detroit, Grosse Pointe, and Highland Park that have not yet been upgraded to a 13.2kV system. However, ratepayers as a whole benefit from increased density by reducing the infrastructure needed to serve the customer base. Thus, it is to everyone's benefit not to adopt a policy that effectively encourages sprawl.

IX. RECOMMENDATIONS REGARDING THE POLE AND POLE-TOP MAINTENANCE AND MODERNIZATION PROGRAM

Q. Do you have any concerns regarding DTE's Pole and Pole-top Maintenance and

[26] *See*, Deol, p. 7.

Modernization ("PTMM") Program?

A. Yes. It is concerning that the backlog of uncompleted PTMM work rose to such a level that the Company paused inspections at the beginning of 2023 to "focus efforts on completing the required construction already identified," and, in 2024 and 2025, only plans to conduct inspections on poles and pole-top equipment until it runs out of funding to complete "the associated construction activities," which means it will fall behind its 10 to 12 year pole inspection cycle.[27]

Q. Why do you find this concerning?

A. As DTE witness Morgan Elliott Andahazy states on page 29 of her testimony, "Poles and pole-top equipment are some of the most critical and visible parts of the distribution and subtransmission grid, and are continually exposed to harsh conditions … causing them to degrade, weaken, and fail over time." DTE needs to be aware of the condition of this extremely important equipment, so it can properly plan for repairs and replacements. Only performing inspections until it runs out of money, rather than staying on the MPSC Staff-recommended 10 to 12 year cycle, is unreasonable and imprudent. The Company's reasoning for limiting inspections is essentially that more inspections will lead to an increased backlog of work. However, failing to inspect poles and pole-top equipment does not magically create a situation where fewer poles are in need of repair or replacement, it is just that fewer of the poles that need such work will be known to DTE. Ignoring the existence of this failing equipment may make it appear that there is a smaller backlog, but it will not mean there physically will not be a backlog. In the short term, this

[27] Andahazy, p. 48-49.

may make DTE feel better about its backlog numbers, but poor inspection processes mean that the utility will not be able to properly plan for its future needs or identify equipment that may need immediate repair or replacement. This is likely to drive up in the longer term and has been shown to be a dangerous strategy for utilities to employ. For instance, using lump-sum inspection payments instead of time and materials contracting that ensured necessary asset inspections would be completed was identified by the California Public Utility Commission as one of the root causes of wildfires for which Pacific Gas and Electric Company was found to be responsible. Exhibit AA-34.

DTE should not be given a pass to fall behind on inspections of PTMM equipment. Doing so would tee up a situation similar to the game of catch-up DTE has been playing (and ratepayers have been paying for) with tree trimming for over a decade.

X. RECOMMENDATIONS REGARDING DTE'S TRANSPORTATION ELECTRIC PLAN PROGRAMS

Q. Do you have any concerns regarding DTE's Transportation Electric Plan ("TEP") programs?

A. Yes. My main concern is that the income eligibility threshold for income-qualified Home Charger Rebates is too low.

Q. What is DTE's proposed threshold to be income-qualified for a Home Charger Rebate?

A. DTE is proposing a threshold of 200% of the federal poverty level, which would be approximately $60,000 for a four-person household.

Q. On page 41 of DTE witness Pina Bennett's direct testimony, she states that this threshold aligns with other DTE low-income programs. Why is it too low for Home

Charger Rebates?

A. Though 200% of the federal poverty level may be an appropriate threshold for other low-income programs, it is simply too low for this program. Generally, households at or below that income level are not purchasing EVs.

Q. Why are such households not purchasing EVs?

A. The EV market does not offer an affordable enough option at this point. Many individuals at that low an income level do not even own a vehicle of any type.

Q. What is your recommendation regarding the income-qualified threshold for Home Charger Rebates?

A. I recommend setting the income-qualified threshold at 400% of the federal poverty level or, alternatively, 300% of the federal poverty level at the very least. On page 42 of DTE witness Bennett's testimony, he states, "DTE Electric may need to adjust the threshold of the Home Charger Rebate program upwards to meaningfully support this segment and encourage EV adoption in Southeast Michigan." If the purpose of this program is to incentivize adoption of EVs (as it should be), it is reasonable to make this rebate available to more households to begin with and adjust the threshold downward if necessary as the EV market changes.

XI. RECOMMENDATIONS REGARDING PILOT PROGRAMS

Q. What is your recommendation regarding the residential home generator pilot?

A. The residential home generator pilot and all costs associated with it should be disallowed. As DTE has acknowledged, "climate change continues to be one of the defining issues of our time." Exhibit AA-35. The Company has a goal of reducing carbon emissions by

65% by 2028 (compared to the 2005 baseline) and of reaching carbon net zero by 2050.[28] Further, DTE has claimed it is "continuing to invest in cleaner sources of power generation," and "protecting our planet, planning for the future, [and] supporting our people and communities." Exhibit AA-35.

A program that explores the ability to remotely shift a customer's electric load to a gas generator as a demand response solution is simply not in line with the Company's stated climate goals or its claims regarding protecting our planet and planning for our future. It is unreasonable and imprudent to spend ratepayers' money exploring a program that will result in *increased* carbon emissions. If the Company wants to explore increased residential resilience and/or demand response options, it could craft a similar pilot using batteries as the remotely accessible power sources, rather than generators that rely on fossil gas.

This pilot and its associated costs should be disallowed.

Q. Do you have any recommendations regarding DTE's strategic undergrounding pilots?

A. Yes. I recommend that DTE (a) expand its strategic undergrounding pilots beyond the City of Detroit, and (b) institute a more transparent and fair process for selecting pilot locations. This goes hand in hand with the need for improved communication and coordination between DTE and local governments.

Ann Arbor has indicated its interest in having DTE do undergrounding pilots in the City to coincide with largescale street projects, but the Company has never taken advantage of

[28] Crozier, p. 9, Figure 3.

this coordination opportunity and never been provided a reason for its failure to be selected for a strategic undergrounding project.

Local governments deserve more transparency and information regarding the pilot selection process and an opportunity to be considered for projects that may be a good fit in our communities.

XII. STREETLIGHTING

Q. Have you had any involvement in Ann Arbor's Streetlight Conversion Project, which is discussed at length in Ann Arbor witness Cyrus Naheedy's testimony?

A. Yes. As the Director of the Office of Sustainability and Innovations, I have been highly involved in this project due to its connection to reducing energy use in the City.

Q. On page 18 of his direct testimony, DTE witness Robert A. Bellini stated, "the Company continues to improve the arrangements for the provision of special-order materials on behalf of municipalities that choose streetlight materials that are not included in DTE's standard streetlight offerings." Can you describe the City's experience in choosing an LED streetlight fixture that was not one of DTE's standard offerings?

A. The City's experience overall with the process of opting for a "special order material" LED fixture has not been positive. It has taken a significant amount of staff time and effort to reach an agreement with DTE regarding the LEDs the City would like to install due to the fact that they are not one of DTE's standard offerings. One of the biggest hurdles the City faced in this process was DTE's initial requirement that the City purchase, maintain, and store backstock in an amount equal to 10% of the lights installed. Though we eventually negotiated this percentage down, it still resulted in City staff

deciding it would be optimal to select only one special order LED streetlight option, even if it determined that different wattages may be better suited to different areas in the City (e.g., main roads vs. residential neighborhoods).

Q. Has DTE indicated whether customers, like Ann Arbor, who have opted to proactively convert to LED streetlights will receive any sort of credit for paying a CIAC up front?

A. No – aside from the $65 per light labor credit that does not come close to reimbursing such customers for their CIAC.

DTE does not appear to intend to offer any sort of future credit to customers who proactively covered the cost of converting to LEDs, despite the fact that all HPS fixtures will be converted to LEDs upon failure starting January 1, 2025.[29]

Q. Why do you believe communities that proactively converted to LEDs should receive a future credit in consideration of their CIAC?

A. Communities that proactively converted to LEDs prevented other communities from contributing to the cost of these conversions by covering the entirety of the cost upfront, so it was never figured into rates. It would be unreasonable, now that LEDs are the standard streetlighting technology and all communities who did not proactively convert will eventually have all their streetlights converted to LEDs at no upfront cost, to not provide a credit to early converters. Otherwise, communities like Ann Arbor will pay for their own LED conversions with no contribution from other communities, and then pay through streetlighting rates for other communities to convert to all LED streetlighting.

[29] Bellini, p. 12.

This is an absurd and unfair result.

Q. What is your recommendation on this issue?

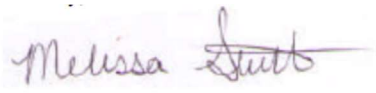
A. Communities who proactively converted their streetlights to LEDs and paid a CIAC up front should receive a credit so that they are not paying both for the entirety of their own conversions and a portion of others'.

Q. Does this conclude your direct testimony?

A. Yes.

Q. Do you swear under penalty of perjury that the statements above are true to the best of your knowledge, information, and belief?

A. Yes.



Dr. Melissa Stults

MS. BRADER: Thank you. That binds in all the testimony and exhibits for the City of Ann Arbor and concludes my motions on behalf of the City of Ann Arbor today, your Honor. With your permission, I'd now like to move to bind in for the Michigan Municipal Association for Utility Issues.

JUDGE WALLACE: Please go ahead.

MS. BRADER: On behalf of the Michigan Municipal Association for Utility Issues, or MI-MAUI, I will be moving to bind into the record the prefiled direct testimony of one pre -- excuse me -- the prefiled revised direct testimony of one witness, along with two sets of exhibits sponsored by that witness.

First, I move to bind into the record the Revised Confidential Direct Testimony of Richard Bunch, consisting of a cover page and 86 pages of questions and answers, as well as the public version of that document. With that testimony, he sponsors 40 prefiled exhibits totaling 91 pages, designated as MAU-1 through MAU-30, and MAU-32 through MAU-41, and I note that Exhibit MAU-28 is designated as confidential. I move to admit those exhibits into the record, and I would also note that Mr. Bunch does not sponsor any rebuttal testimony.

JUDGE WALLACE: So that was MAU-1 through MAU-30, MAU-32 through MAU-41, and the confidential

exhibit was which one?

MS. BRADER: MAU-28.

JUDGE WALLACE: O.K. Is there any objection to binding in the confidential and public Versions of the revised direct testimony of Mr. Bunch?

Hearing none, that testimony is bound in.

Is there any objection to the admission of Exhibits MAU-1 through MAU-30, MAU-32 through MAU-41, noting that Exhibit MAU-28 is confidential and will not be available in the public record?

Hearing no objections, those exhibits are admitted.

(Pubic Direct Testimony bound in.)

(Confidential Direct Testimony found on Page 5379 of the Confidential Record.)

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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 for the generation and distribution of electricity and for other relief.	U-21534 ALJ Sally Wallace

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REVISED TESTIMONY OF RICHARD BUNCH

ON BEHALF OF

THE MICHIGAN MUNICIPAL ASSOCIATION FOR UTILITY ISSUES

~~July 26~~August 29, 2024

REVISED DIRECT TESTIMONY OF RICHARD BUNCH FOR MI-MAUI
CASE NO. U-21534

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I. INTRODUCTION & QUALIFICATIONS

Q. Please state for the record your name, position, and business address.

A. My name is Richard Bunch. I am Executive Director of the Michigan Municipal Association for Utility Issues (MI-MAUI). I am also a senior consultant at 5 Lakes Energy, LLC. My business address is 220 MAC Ave, Suite 220, Lansing, MI.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of Michigan Municipal Association for Utility Issues (MI-MAUI).

Q. What is MI-MAUI?

A. MI-MAUI is a non-profit membership association formed by Michigan municipal governments to provide them with a collective voice and technical support in their relationships with regulated utilities and in Michigan Public Service Commission proceedings.

Q. Please summarize your experience in the field of utility regulation.

A. I have worked since 2015 in positions related to clean energy, primarily on behalf of local governments. A significant portion of that work has included analysis of MPSC rate and other cases and supporting local government participation in rate cases and other MPSC proceedings. From 2015 to 2017 I organized and led the Municipal Street Lighting Coalition, a group of 24 municipalities served by DTE Energy, which intervened in Cases U-17767, U-18014, U-20836 and U-21297 and participated in the subsequent MPSC-ordered street lighting collaborative. I organized and supported the intervention of several municipalities receiving street lighting services from Consumers Energy in cases U-20134, U-20697, U-20963, U-21224 and U-21389. I have submitted comments in several other case dockets on behalf of MI-MAUI and have participated in various MI Power Grid

working groups and the Electric Distribution Planning working group. I directed MI-MAUI's intervention in DTE Energy's Voluntary Green Power case U-20713.

In the field of consumer protection, I am president and board chair of the Washington Public Interest Group (WashPIRG), an independent, non-partisan, non-profit organization based in Seattle that works to protect consumers and promote good government. I am also an officer of the WashPIRG Foundation, an affiliated research and public education organization. I was Executive Director of WashPIRG from 1989 to 1992 and worked on a number of consumer protection issues during that time and in more junior positions prior to that. I also served until 2020 as an officer of the PIRG in Michigan (PIRGIM) Education Foundation, a non-partisan consumer protection and good government public education and research organization based in Ann Arbor.

I am currently a stakeholder co-chair of the Commission's Data Analysis and Regulatory Review working group, and I am a member of the Commission's Low Income Energy Policy Board.

My energy-related work experience, educational and professional development background are summarized in my resumé.[1]

Q: Please list your training and education relevant to the field of utility regulation.

- EUCI Outdoor Street Lighting Conference, June 2019
- EUCI Electric Cost-of-Service - Essential Concepts for a Changing Industry, July 2019
- MSU-IPU Accounting and Ratemaking course, September 2020
- EUCI Utility Green Tariffs: A to Z course, November 2020
- MSU-IPU Advanced Regulatory Accounting and Auditing course, October 2021

[1] See Exhibit MAU-1, Resume of Richard Bunch.

- NRRI Regulatory Training Institute, Regulating Public Utility Performance course, 2022.

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

A. I have previously testified before the Michigan Public Service Commission (Commission) in the following cases:

- Case U-20530 (I&M PSCR Reconciliation case)
- Case U-20561 (DTE Electric Company Electric General Rate Case)
- Case U-20697 (Consumers Energy Company Electric General Rate Case)
- Case U-20836 (DTE Electric general rate case)
- Case U-20963 (Consumers Energy Company Electric General Rate Case)
- Case U-21087 (DTE Electric PrePay case)
- Case U-20836 (DTE Electric Company Electric General Rate Case)
- Case U-21224 (Consumers Energy Company Electric General Rate Case)
- Case U-21297 (DTE Electric Company Electric General Rate Case)
- Case U-21389 (Consumers Energy Company Electric General Rate Case)

I have testified before the Kentucky Public Utilities Commission in rate cases 2020-349 and 2020-350, the combined Kentucky Utilities and Louisville Gas & Electric electric and gas rate cases.

Q. What is the purpose of your testimony?

A. I am testifying on behalf of MI-MAUI regarding DTE Electric's (the Company) customer billing practices, coordination of infrastructure projects with local governments and street lighting service, rates, and tariffs.

Q. Are you sponsoring any exhibits?

A. I am sponsoring the exhibits listed below. Exhibits MAU-1 through MAU-9, MAU-12 through MAU-16, MAU-18 through MAU-31, MAU-33, and MAU-35 through MAU-38 were prepared by me. Exhibits MAU-10, MAU-11, MAU-17, MAU-32, and MAU-37 were prepared under my direction.

Exhibit MAU-1:	Resume of Richard Bunch
Exhibit MAU-2:	DTE 'Ways to Pay' Kiosks Webpage
Exhibit MAU-3:	DTE Response to MAUIDE-3.17a (S1)
Exhibit MAU-4:	DTE Response to MAUIDE-3.14 (S1)
Exhibit MAU-5:	DTE Response to MAUIDE-3.13
Exhibit MAU-6:	DTE 'Ways to Pay' Authorized Agents Webpage
Exhibit MAU-7:	DTE Response to MAUIDE-3.15
Exhibit MAU-8:	DTE Response to MAUIDE-3.17a Attachment
Exhibit MAU-9:	DTE Response to MAUIDE-3.16
Exhibit MAU-10:	DTE Kiosk Census Data
Exhibit MAU-11:	National Utility Cash Payment Requirements
Exhibit MAU-12:	Identity Theft Statistics
Exhibit MAU-13:	DTE Response to MAUIDE-4.19a
Exhibit MAU-14:	Bellini Rebuttal Testimony U-21297 p. 9-10
Exhibit MAU-15:	City of Ferndale LED Conversion Cost Proposal
Exhibit MAU-16:	Consumers Energy LED Bill Credit
Exhibit MAU-17:	U-21585 Consumers Witness Schmoekel Testimony, p. 18
Exhibit MAU-18:	Electric Sales Forecast Reduction

Exhibit MAU-19:	DTE Response to MAUIDE-4.28b
Exhibit MAU-20:	DTE Response to MAUIDE-6.52
Exhibit MAU-21:	DTE Response to MAUIDE-6.53
Exhibit MAU-22:	U-20147 DTE 2023 EDIIP Comments MI-MAUI
Exhibit MAU-23:	DTE Response to MAUIDE-4.26
Exhibit MAU-24:	DTE Response to MAUIDE-4.24
Exhibit MAU-25:	U-21297 Witness Bellini Testimony, p. 18
Exhibit MAU-26:	DTE Response to MAUIDE-6.55
Exhibit MAU-27	U-20836 Bellini Rebuttal excerpt
Exhibit MAU-28:	DTE Response to MAUIDE-6.56 REDACTED
Exhibit MAU-29:	DTE Response to MAUIDE-4.20
Exhibit MAU-30:	DTE Response to MAUIDE-5.47 - GCJ_J Specs
~~Exhibit MAU-31:~~	~~Ann Arbor City LED Conversion Webpage~~
Exhibit MAU-32:	Consumers Energy LED Streetlight Crossovers
Exhibit MAU-33:	Grand Rapids LED Conversions
Exhibit MAU-34:	LED Luminaire Plant Balance Disallowance
Exhibit MAU-35:	COS Cost Comparisons from WP U-21534 RAB Lighting Rate Model
Exhibit MAU-36:	Google Search Results of Capital Improvement Plans
Exhibit MAU-37:	DTE Response to MAUIDE-2.5
Exhibit MAU-38:	DTE Response to AADE-1.7
Exhibit MAU-39:	DTE Response to MAUIDE-2.8
Exhibit MAU-40:	DTE Response to MAUIDE-2.7
Exhibit MAU-41:	DTE Response to MAUIDE-1.2

II. DTE CASH PAYMENT REQUIREMENTS

Q. How can most customers pay their DTE bills?

A. Most customers have a range of options, including automatic bill payment (using both withdrawals from bank accounts or credit cards), by check, money order, credit or debit card and in cash. If customers want to pay by mail, then they must use either checks or money orders.[2]

Q. Are there DTE customers who have been required to pay their bills only in cash for a year?

A. Yes. In 2023, 48,410 customers were required to pay in cash; this was a little more than two-thirds of customers subject to payment restrictions.[3]

Q. Under what conditions does DTE say it imposes the cash-only payment requirement?

A. The Company states, "Customers with a returned payment and arrears greater than $100 are subject to the payment restriction." If arrears are $100 or less, then "two returned payments with or without arrears will trigger the same restriction."[4]

Q. Does the cash payment requirement apply only to customers facing shutoff?

A. No. Customers who have made payments on time for months are still required to pay in cash for one year following a returned payment, according to the Company's communications.

Q. If a customer had a monthly electric bill of $101, was a victim of identity theft, cancelled a credit card as a result, and forgot to update their DTE payment method

[2] See Exhibit MAU-2 (DTE "Ways to Pay").
[3] Exhibit MAU-3, response to MAUIDE-3.17a (S1).
[4] Exhibit MAU-4, response to MAUIDE-3.14 (S1).

to change the card on file, under current practice the Company may require them to pay in cash for a year?

A. Yes, that scenario is consistent with the Company's statements regarding when it could impose this restriction.

Q. How does DTE inform customers that it will require them to provide payment in cash?

A. DTE's rate book does not include any specific requirement for the form of notice (e.g., phone call, email, letter), advance notice or content of notice.[5] In practice, DTE states that it sends the customer an e-mail including the following text "For the next 12 months you are required to make your payment using cash at a kiosk or at an authorized payment location."[6]

Q. If required to pay bills in cash, how can customers do that without incurring additional fees?

A. The only way to pay bills in cash without incurring additional fees is to pay at a kiosk. Otherwise, customers will have to use an authorized agent and pay that agent a fee. See R. 460.123(5)(b). The amount of the fee varies from agent to agent and is not disclosed on DTE's website.[7]

Q. Does DTE use geographic criteria when imposing the cash-payment-for-a-year restriction, such that it ensures customers who must pay in cash have access to kiosks?

[5] Exhibit MAU-4, MAUIDE-3.14 (S1).
[6] Exhibit MAU-5, response to MAUIDE-3.13, attachment 2.
[7] Exhibit MAU-6, DTE Ways to Pay – authorized pay agents webpage.

A. No.[8]

Q. DTE's website says kiosks "are located all across the service territory."[9] Do you believe this is an accurate statement?

A. No. There are only five communities with kiosks currently: Detroit, Ecorse (which borders Detroit), Harper Woods (which borders Detroit), Highland Park (which is surrounded by Detroit), and Redford Charter Township (which borders Detroit).[10]

Q. Do you believe that most DTE customers that are required to pay in cash are functionally required to pay a processing fee to an authorized agent every time they are billed for a year?

A. Yes. Even if all the people in Wayne County who were required to pay in cash in 2023 (23,178) lived in and around the five Detroit-area communities with kiosks (which is unlikely), then more than half of the people required to pay in cash would not have access to fee-less payments. For instance, in 2023, there were 10,040 cash-only customers in Oakland County, 8,488 in Macomb County, 2,365 in Washtenaw County and 1,211 in Saint Clair County.[11] DTE currently operates no kiosks in these counties.

Q. Does every customer ordered to pay in cash at least have access to an authorized agent or kiosk within a 5-mile radius of their billing address?

A. Probably not. For example, Sanilac County has only one authorized agent (in Sandusky)

[8] Exhibit MAU-4.
[9] Exhibit MAU-2.
[10] Exhibit MAU-7, response to MAUIDE-3.15.
[11] Exhibit MAU-8, attachment to response to MAUIDE-3.17a (S1).

but in 2023 had 262 customers who were required to pay in cash.[12] Parts of Sanilac County are 30 miles away from Sandusky.

Commission Rules Regarding Cash Payments

Q. Do the Commission rules permit utilities to require customers to pay only in cash or by money order, and to bar access to other payment options?

A. As I read them, such restrictions are permitted only when the customer is facing shutoff. In a Rule labelled as regulating the "manner of shutoff," a utility must permit the customer to "pay in any reasonable manner, including by personal check, credit card, or debit card" but the rule clarifies that if a customer has tried any of those three methods and in the last year has had payment denied for a reason other than financial institution error, then "payment by personal check, credit or debit card" is not reasonable. R. 460.142(4). While Rule 460.123 discusses automatic bill payment plans, it does not address whether and when customers may use them.

Q. Is the practice of requiring customers to pay in cash for a year included in the Company's tariff?

A. The cash-payment provision language included in DTE's rate book at section C4.6B mirrors the language of found in Rule 460.142(4), without reference to a shutoff scenario.

> Payment by personal check, credit or debit card is not reasonable if the customer has paid with a personal check, credit or debit card within the last 12 months and at least 1 check has been returned for insufficient funds or no account, or at least 1 credit or debit card payment has been denied excluding financial institution error.

[12] Location of authorized agents determined from DTE's "Ways to Pay" webpage. Number of cash-payment customers in Sanilac County taken from U-21534 Exhibit MAU-8, attachment to response to MAUIDE-3.17a.

Q. Are forms of payment other than "personal check, credit or debit card" discussed elsewhere in the rules?

A. Yes. The rule listing forms of payment that "are not reasonable" to accept to avert shutoff does not include automatic bill payment plans, which are referenced elsewhere in the rules.

Q. What do you conclude from your review of the Billing Rules and DTE's rate book?

A. I conclude that DTE's cash-payment requirement is inconsistent with, if not explicitly prohibited by, the Billing Rules.

Q. What do the billing rules contemplate as the method by which to balance utility interests with customer interests, in situations when a check has bounced or a credit card has been declined?

A. The rules specify that in such situations, the utility may require the customer to provide a deposit. R. 460.109(1)(f). Those deposits are returned to the customer with annual interest of 5% after a year of making on-time payments. R. 460.111(8).

Q. Does DTE's rate book state that a customer who has bounced a check or had a declined credit card payment may provide a deposit consistent with Rule 460.109(1)(f)?

A. No, it does not.

Q. In what way is a deposit potentially better for a utility than requiring customers to pay in cash for a year?

A. Because the deposit is paid up front, the utility has greater certainty that overdue bill amounts may be recouped if the customer falls into arrears.

Q. In what way is a deposit potentially better for a customer than being required to pay in cash for a year?

A. There are at least three reasons a customer might prefer to pay a deposit rather than pay in cash for a year: safety, cost, and the reduced burden of finding a payment location.

Q. Why would a deposit be safer for customers than paying in cash?

A. Having to carry a large amount of cash on a regular schedule to a known location can create a risk of robbery. The fact that such a risk is real and not merely perceived is shown by the fact that in recent years, DTE experienced "kiosk theft activity" and requests from store owners to remove kiosks "to protect their business from possible theft activity."[13]

Q. How many kiosks have been taken out of service for theft activity?

A. Although DTE did not provide specific data on this, the Company did report it has cut the number of kiosks by two-thirds in the last five years, and identified only one instance when a kiosk was removed for reasons not related to theft.[14] Specifically, DTE had a total of 38 kiosks in operation after 2019 and only operates 13 kiosks now.[15]

Q. Does DTE warn customers ordered to pay in cash about the kiosk theft activity it has experienced or that its store owners have warned the Company about?

A. No. Despite the Company's experience, DTE's website states that the kiosks "…offer a safe, secure place to access account information and make payments."[16]

Q. Why could paying a deposit be cheaper for customers than paying in cash?

A. While provision of a deposit is often burdensome to a customer (requiring up-front cash), at the end of a year of making payments on time, deposits are returned in full with 5% interest to the customer. If a customer pays in cash at any location but one of the thirteen

[13] Exhibit MAU-9, response to MAUIDE-3.16.
[14] Exhibit MAU-9, response to MAUIDE-3.16.
[15] Exhibit MAU-7, Response to MAUIDE-3.15.
[16] Exhibit MAU-2.

remaining kiosks, then the customer must pay a processing fee each time, and will never recoup any of that money, much less any interest they would have earned.

Q. Why could paying DTE a deposit be more convenient for a customer than paying in cash?

A. As I discussed above, most customers have poor access to kiosks, and some customers do not have any option that accepts cash payments within a 5-mile radius. Therefore, the ability to make a single payment and then use normal payment methods could prevent having to make a monthly trek to a particular location.

Q. Are there customers for whom having to pay in person would be even more problematic?

A. Yes. For example, customers who have medical conditions that compromise their immune systems or render them homebound may find the requirement to pay in cash imposes unreasonable logistical or personal safety risks when trying to deliver cash payments.

Q. Does the geographic distribution of the remaining kiosks create concerns in other dimensions?

A. Yes. In general, Commission rules prohibit requiring a deposit for reasons including race and residence location. R.460.108. When examining where kiosks are located, all of them are in higher-poverty areas that have high African-American and other non-white populations. There are other communities within DTE's service territory with comparable size and poverty rates but a racial makeup that is more heavily white. For instance, Lapeer and Port Huron Charter Township are similar in size and poverty rate to Ecorse. Hazel Park, Port Huron, and Mt. Clemens are similar in size and poverty rates to Harper Woods.[17]

[17] Exhibit MAU-10, DTE Kiosk Census Data.

Yet only Detroit and a few inner-ring suburbs have kiosks.

Q. Do customers who do not live near payment kiosks have any reasonable way to avoid paying the authorized agent processing fees?

A. In my opinion, they do not. In effect, to pay their bill they are compelled to pay an unavoidable fee, additional to the tariff, that the Commission has not reviewed or approved. In addition, they face security risks and inconveniences related to securing significant sums of cash and traveling to a payment location at least once per month.

While the Billing Rules authorize utilities to use payment agents who may assess fees, most customers are not compelled to pay those fees because they have other ways to pay their bills; in other words, if they pay the processing fee it is by choice. Customers required to pay in cash have no option, and if they do not live reasonably close to a DTE kiosk they will have little choice but to pay through an agent and incur the processing fee.

Increased Ratepayer Costs from Requiring Cash-Only Payments for a Year

Q. Do other large Michigan utilities require their customers to pay in cash for a year?

A. ~~It does not appear they do.~~ The websites, and MPSC-approved tariffs~~,~~ and rate books ~~and websites~~ of Consumers Energy and Indiana-Michigan Power do not state any circumstances in which the utility may require a customer to pay their bill in cash.[18]

Q. Do any municipal electric utilities in Michigan impose similar cash-payment requirements on their customers?

A. It does not appear they do. MI-MAUI reviewed the websites of thirty-nine municipal utilities in Michigan, of which all but two had websites explaining how bills could be paid. None of these sites stated requirements for customers to pay in cash under any

[18] Exhibit MAU-11, MI-MAUI Cash Payment Requirements research.

circumstances.[19]

Q. Was MI-MAUI able to identify large utilities outside of the state of Michigan that require their customers to pay in cash?

A. No. MI-MAUI reviewed the websites of seven of the biggest electric investor-owned electric utilities operating outside of Michigan. None of these websites stated requirements for customers to pay in cash under any circumstances.[20]

Q. What do you conclude from this review of other utilities' practices?

A. DTE is the only utility we were able to identify among a large peer sample in Michigan and nationally that has a published policy of regularly requiring cash payments from customers. Therefore, DTE is not following common or standard practices among its peers in Michigan and nationwide, who do not appear to require customers to pay in cash for a year, if ever.

Q. Do you believe the practice of requiring cash-only payments for a year harms all ratepayers by increasing uncollectibles?

A. Yes. It is common sense that making it harder for people to pay you is generally going to decrease your collections and drive up your collection costs. Moreover, given that the Department of Justice reported that 1 in 10 Americans were victims of identity theft in 2021,[21] situations in which customers may be needing to freeze a bank account or cancel a credit card and may not remember to change the DTE form of payment are likely to be common and easily rectifiable by providing another credit card or setting up payment from an alternative bank account. Customers given the opportunity to rectify these situations

[19] Exhibit MAU-11.
[20] Exhibit MAU-11.
[21] Exhibit MAU-12, US Department of Justice press release, identity theft statistics.

with little inconvenience means that DTE is more likely to get paid. I believe this is why other utilities do not impose such a requirement.

Imposing a cash-payment on some customers – even if they have no reasonable explanation for their returned payment – is likely to drive up uncollectibles. For example, it would simply be imprudent to make customers who are enrolled in shutoff protection programs pay in cash, because they will be much more likely not to bother paying at all. If the Commission finds that the Company may continue imposing a cash-only requirement on some customers, it should at least prevent the Company from recovering uncollectible costs caused by imprudent management decisions of this nature.

Q. How can DTE incentivize customers to present valid forms of payment, and avoid increased collections costs caused by returned payments, if it cannot require customers to pay in cash?

A. DTE has other means to minimize the impact on the cost of service of returned forms of payment and to encourage valid forms of payment.

First, DTE assesses customers a $15 charge for payments returned by banks or other financial institutions under section C4.6c of the rate book.

Second, returned payments frequently result in late fees, limited to 2% of the portion of the bill, net of taxes, that is delinquent.[22]

These provisions limit cost-of-service impacts on other ratepayers of returned payments and establish appropriate incentives for customers to present valid forms of payment. In addition, per my preceding point, there is no reason to think that making it harder for customers to pay their bills will reduce uncollectible expense.

[22] R460.125, late payment charges.

Q. Is the Company's late fee policy appropriately documented in its rate book?

A. No, it is not. The Company's rate book section C4.8A, Late Payment Charge Residential, refers to Rule 460.122. This reference is incorrect. Rule 460.122 is titled Cycle Billing. The correct reference is to Rule 460.125. The Commission should order the Company to correct this error in its rate book. Because the Billing Rules were recently revised, it may be prudent for the Company to conduct a general reconciliation of its rate book to the revised rules.

Recommendations Regarding Cash Payment Requirements

Q. If the Commission agrees that DTE's practice of requiring customers not facing imminent shutoff to pay in cash is a violation of the billing rules, what do you recommend it do?

A. The Commission should order an amendment to DTE's tariff to restrict the Company's ability to require customers to pay in cash to the specific and narrow circumstance covered by Rule 42, because doing otherwise is a violation of the billing rules and results in an unauthorized rate for many customers.

Q. If the Commission does not agree the billing rules prohibit DTE from imposing cash-only requirements when payments are returned, what notice requirements should it order the Company to observe?

A. The Commission should create requirements pertaining to both the form and content of such notices.

First, the Commission should order the Company to mail notice to the customer, in addition to the email notice it already provides.

Second, the notice should state that the cash-payment requirement pertains only to the

person whose payment was returned. The Company should continue to accept standard forms of payment from others. Imagine a restaurant that, following presentation of a declined credit card, refused to accept anything but cash from everybody else in the party: such a policy would be petty and self-defeating.

Third, the notice should describe how a customer may appeal imposition of the requirement by providing a reasonable explanation for the returned payment or by demonstrating undue hardship from paying in cash.

Q. If the Commission does not agree the billing rules prohibit DTE from imposing cash-only requirements, but does agree the Company's practice of requiring it for customers in vulnerable or protected groups is unreasonably burdensome, what do you recommend the Commission do?

A. The Commission should order the Company to ensure that no customer will be unreasonably burdened by a requirement to pay cash. The Commission should specify that no customer enrolled in critical care protection or medical emergency protection may be required to pay in cash. Per my preceding point, customers should be afforded an appeal process allowing them to present evidence of undue hardship or unreasonable burden.

Q. If the Commission does not agree the billing rules prohibit DTE from imposing cash-only requirements, but does agree the Company's practice of requiring it for customers who cannot access a kiosk imposes on them a higher rate than is authorized due to the effective requirement to pay processing fees with every bill, what do you recommend the Commission do?

A. The Commission should find that before imposing a requirement that a customer pay in cash, the Company must ensure there is an opportunity for the customer to pay their bill at

a location without an additional fee within five miles of the billing location.

Q. If the Commission does not agree DTE's cash-only-for-a-year requirement for some customers violates the billing rules, but does believe that the practice unreasonably increases uncollectibles, what do you recommend?

A. The Commission should disallow 1% of the expense amount uncollectibles contribute to the revenue requirement, and disallow the costs associated with the high rate of theft, etc. of kiosks that has also been borne by ratepayers.

Q. What is the basis for the recommendation regarding 1% of uncollectibles?

A. DTE does not keep data that would allow us to determine the degree to which customers required to pay in cash for a year default compared to customers not required to do so. Therefore, the 1% number is a reasonable assumption that this practice has driven up uncollectibles, but also recognizes that the default rate from approximately 70,000 customers is likely to make up a small percentage of overall revenue.

Q. Do you have any other recommendations for the Commission on this topic?

A. On a related topic, I recommend the Commission order the Company to correct the erroneous reference regarding late payment fees to Rule 460.122 in section C4.8A of the rate book. The correct reference is to Rule 460.125.

III. STREETLIGHTING

Q. Please summarize why local governments are concerned about street lighting services provided by DTE.

A. Local governments are concerned about the street lighting services they receive from DTE for fiscal, service delivery and social and environmental policy reasons.

For many local governments, street lighting is their biggest utility cost. They need to

deliver good street lighting service, but they also need it to be cost-effective, to be appropriately responsive to their taxpayers. My testimony here is mostly concerned with costs.

Streetlighting is an important municipal service. Badly designed or unreliable street lighting reflects poorly on the capabilities of the local government, even if the service is provided by DTE. Part of my testimony here is concerned with outage reporting, a key accountability component that can help improve reliability. Another part of my testimony addresses O&M priorities and costs.

Street lighting also impacts attainment of social and environmental policy goals. As the biggest electricity use for many local governments, streetlights that use more electricity than is necessary to achieve lighting standards make it harder to achieve local climate goals. A growing number of cities are also adopting lighting ordinances intended to reduce obtrusive light, including glare, light trespass, and light pollution. These phenomena can have public health, environmental and scientific impacts to which communities are increasingly attuned. Alignment of utility rates and practices with public policy goals, including state and local climate goals, is especially important for the streetlighting class of customers, which is made up entirely of governments.

Q. What street lighting topics will you address in testimony?

A. I will follow the outline used by DTE witness Bellini, and address the following topics in turn:

- Community Lighting Assets
- Community Lighting Sales Forecast
- Company Preventive Maintenance Programs

- Outage Restoration Activities
- Community Lighting Operation & Maintenance and Capital Expenditures
- LED Luminaire Selection Methodology Specific to HID to LED Conversions
- Community Lighting Rate Design

Community Lighting Assets

Q. Do you support phasing out HPS streetlights and replacing them with LED luminaires upon failure?

A. I agree that HPS fixtures should be phased out, because LEDs were the standard offering before DTE recognized that. I testified to this effect in case no. U-21297, DTE's previous electric rate case. I agree that any HPS fixture that fails should be replaced with an LED luminaire.

Q. Would you recommend even speedier phasing out of HPS streetlights than witness Bellini recommends to lower overall costs?

A. Yes, I would. To reduce the number of truck rolls necessary for the conversion, I would go slightly further: any maintenance event requiring a visit to an HPS fixture, including its mast arm, pole, and wiring, should result in replacement of the fixture. Making another repair now, only to return in a few years when the lamp burns out, is an expensive waste of crew time and leaves an inefficient fixture in service all that time.

Q. Do you support DTE's proposal to allow for immediate replacement of failed HPS with LED luminaires upon customer request, without assessment of a contribution in aid of construction ("CIAC")?

A. Yes: I support witness Bellini's commitment to allow any customer to request that the Company replace failed HPS lights with LED luminaires starting immediately, rather than

after stocks of replacement HPS lamps are depleted, without assessing a CIAC.[23]

Q. Do you support DTE's proposal to continue to require CIACs for group conversions of HPS fixtures to LED technology?

A. No. No CIAC should be assessed, because a planned conversion of a set of lights *en masse* ("group conversion") would lower overall costs compared to a conversion done as lights in the same area or on the same street burn out at different times ("reactive conversion"). There is no justification to charge CIAC for a customer-requested project that will be cheaper for the Company to implement than if the customer did nothing and thus reactive conversions were the way every light in a City were addressed.

In addition, as witness Bellini noted in his testimony in case no. U-21297, charging a CIAC when LEDs are the standard offering creates a situation where municipalities that act proactively and choose to pay for the entirety of their conversion will effectively subsidize future LED municipal conversions; this problem should not be deliberately exacerbated by continuing the practice when LEDs have become the default.[24]

Finally, if reactive conversions were actually cheaper and a CIAC was appropriate, then credits would need to reduce the CIAC for group conversions, as witness Bellini notes (though I believe the proper credit would be calculated differently than the labor credit witness Bellini describes).

Q. Why do you find the proposal to continue charging a CIAC for conversions to be inappropriate?

A. That is concerning to me for a few reasons. First, we have argued for some time that LEDs

[23] Exhibit MAUI-13, discovery response 4.19a.
[24] Exhibit MAU-14, Bellini rebuttal, case U-21297, p. 10 lines 6-8.

are becoming the standard light and people should not have to pay up front as if they were a specialty item. The Company argued this was not true right up until the time their suppliers told them they would not even carry HPS lights anymore. The Company's communication to its customers about the change in policy seems like an effort by DTE to entice customers to rush into a process that will result in those customers covering the project costs for converting from HIDs to LEDs when they would not have to pay hundreds of thousands – or even millions – of dollars up front for that conversion if they just waited for their existing lights to fail.[25] It also raises concerns regarding whether those customers will essentially pay for their conversion and the conversion of other customers, without getting any credit for that.

Q. Do you agree that it is cost-effective for DTE to continue to re-lamp HPS light fixtures until its inventory of HPS lamps is depleted?

A. No, I do not. DTE has testified in the last rate case, when it was arguing that a CIAC should continue to be charged for LED conversions because LEDs should not be viewed as the default offering, that some customers prefer HPS fixtures.[26] Assuming Mr. Bellini is correct, then the remaining stock of HPS fixtures should be reserved for those customers who request them.

Moreover, for customers who do not actively prefer HPS fixtures, it is wasteful to keep an HPS fixture in service. It uses much more electricity than an LED luminaire and requires more-frequent service, which is a major cost-driver. Every HPS fixture that DTE relamps can be expected to remain in service for another eight years – the rated life of the HPS

[25] Bellini Exhibit A-25, Sch O3.
[26] Exhibit MAU-14, Bellini rebuttal, case U-21297, p. 9-10.

lamps that DTE uses. Converting luminaires to LED at the first service opportunity reduces the customer's tariff significantly, rather than pushing realization of that savings out another eight years.

Q. What is your recommendation to ensure that streetlighting rates are based on the most efficient practices?

A. The Commission should deny the proposal to continue a CIAC for group LED conversions. Absent that, the Commission should put DTE on notice that costs of any truck roll to a streetlight in the eight years following replacement with an HPS instead of an LED light will be presumed to be unrecoverable, a presumption that could be rebutted and recovery assumed if the Company can show the roll would have been reasonable and necessary if an LED had replaced the HPS light (e.g. for a pole knockdown event).

Q. Would your recommendation be a departure from past practice, since DTE historically collected CIAC for customer-requested conversions of HPS fixtures to LED?

A. Yes: until now, any conversion of an HPS fixture to LED has been done only at customer request and has required a CIAC.

Q. If as you recommend, customers should get LED group conversions without paying CIAC up front, won't they be getting something for free that they formerly had to pay for?

A. No, they will not get LEDs for free. DTE will recover the cost of new LEDs through its tariff, as it already does. In fact, the current system of collecting CIAC creates the actual equity problem, because customers who pay for conversions pay the same tariff, including LED cost recovery, as customers who did not pay up front (e.g., customers whose Mercury

Vapor (MV) fixtures were replaced upon failure without a CIAC payment). Moreover, the continuation of a CIAC charge as Bellini recommends is poor policy as well as being unfair to customers: it will likely slow societal take-up of the environmental and cost-savings associated with LED conversions, since customers who wait could get the same benefit for free.

Q. Many customers already paid up front to get LEDs. Are you arguing that customers who have not invested in LEDs should get the same benefit without having the same costs?

A. I agree it is not fair for one customer who paid for their LED luminaires to pay the same tariff as another customer who got them at no out-of-pocket cost. It is also not fair that customers be charged for installation of the standard offering (LEDs). I believe there are ways to effectively address the potential disadvantage to those who did pay without knowing that LEDs would become the standard offering, as other utilities have done successfully.

Q. Can you give a specific example that will illustrate the cost implications of DTE's proposal for communities that chose to pay a CIAC for LED group conversions in prior years?

A. Yes, I can. Several years ago, the City of Ferndale, a MI-MAUI member, paid DTE $418,240 to convert all its streetlights to LED.[27]

Under DTE's reactive-conversion proposal, going forward other customers will get their LEDs without having to pay CIAC, via reactive conversions. LED rates will rise as LED luminaire plant-in-service balances rise. Ferndale cannot benefit because all its lights are

[27] Exhibit MAU-14, City of Ferndale LED conversion quote from DTE.

already LEDs, so its rates will rise to pay for other customers' LEDs. That would not be fair to Ferndale.

Q. What rate structure would be more reflective of the cost-of-service principle in ratemaking for LED "early adopters" like Ferndale?

A. Ferndale should not have to pay the portion of the LED rates, going forward, that recover costs of installing other customers' LEDs. Fortunately, we already have a Commission-approved model for handling this exact situation. Several years ago, Consumers Energy decided to discontinue charging customers CIAC for LED conversions, and instead to convert any HID fixture to LED when any kind of maintenance visit was required. Recognizing that rate-basing no-cost conversions would be unfair to customers who had previously paid for them, Consumers worked out a system of time-limited bill credits that protect early-mover LED customers against the rate impacts of those later no-CIAC conversions.

Q. How does Consumers Energy determine its bill credits for early adopters?

A. The Consumers bill-credit has three notable features: first, the credits are time-limited, meaning the credit scheme will end as of a specified date. Second, every customer receives the same credit amount per LED per year (only for LEDs they paid for through CIAC), regardless of the amount of original CIAC they paid or current tariff. Third, the credit amount is adjusted each time new rates incorporate changes in LED plant in service balances. I recommend that DTE bill credits have the same three features.

Q. When should bill credits sunset?

A. I recommend that the bill credits sunset after DTE has replaced half of the LEDs that were paid for by CIAC fees. At that point, it becomes reasonable for those early-mover LED

customers to end the credit because the CIAC contribution will have been effectively exhausted and replacement cost for those LEDs is recovered through rates.

DTE depreciates LEDs on a 15-year schedule. Although a few LEDs were installed earlier, I would recommend starting the 15-year clock at 2018, meaning that the bill credits would continue through 2033.

Q. Can you illustrate how this 2033 end to the credit would be applied in the Ferndale example?

A. Ferndale's LED conversion was finished in 2020. Ferndale's LEDs, according to DTE's depreciation policy, should last, on average, through 2035. To end bill credits much before 2035 would be to charge Ferndale for LED conversions they do not benefit from – i.e., a cost they do not cause; to credit after 2035 would not be appropriate.

The choice of 2033 also roughly coincides with the end of the period over which DTE will be replacing HPS fixtures with LEDs. DTE uses HPS lamps rated to last for eight years, meaning the great majority will burn out by 2033. Consequently, reactive conversion of HPS fixtures to LED will stop adding appreciably to the rate base after 2033.

Q. Why use a single year when customers' installation timelines varied?

A. Using a fleet approach would be much more workable, less confusing to customers and be much easier to administer. A perfectly equitable credit would account for when each customer's CIAC-paid LEDs entered service. DTE does not track service records of individual streetlights with the granularity necessary to establish a credit schedule for each light or even each conversion project.

Q. What data should be used to determine the credit amount?

A. The test-year revenue requirement associated with rate-based LED conversion costs should

be tracked. Customers who were assessed CIAC fees for LED conversions should not contribute to that cost recovery. This calculation should be performed separately for UG and OH lights because they have different luminaire costs. The resulting figure gives the annual amount that should be credited back to customers for each LED paid for by CIAC. I attach the exhibit provided by Consumers Energy in rate case no. U-21389 showing the inputs and calculation method they use.[28]

Consumer's methodology is instructive, but DTE may reasonably use a simpler approach. Consumers accounts for costs of all rate-based conversions going back several years. Until now, DTE has rate-based conversion costs only for failed MV fixtures, and it is reasonable to assume those conversions benefitted all customers with reasonable equity. Thus, DTE should be able to track only past CIAC-paid LED conversions to figure the credit amount. I recommend that the credit should be the same for all CIAC-paid LEDs and should be recalculated with each successive rate case because the number of rate-based LED conversions and the associated revenue requirements will rise over time. Just like the bill credit sunset timeline, the bill credit amount would be prohibitively difficult and confusing to implement with perfect equity. Ideally, the bill credit amount would be figured separately for each LED model and wiring type, and the rate impact would be divided by the number of LEDs of that model that were paid for through CIAC. In my opinion, this level of accuracy would be more trouble than it is worth and would be confusing to customers; it is also likely that DTE does not have the installation and cost records for every conversion project that this approach would rely upon as inputs.

Q. How do you recommend such a credit be implemented?

[28] Exhibit MAU-16, Consumers LED bill credit worksheet.

A. I recommend that the Commission instruct DTE to file a bill credit method and initial amount with its next rate case, including the features I have described here. I also recommend that the Commission instruct DTE to consult with staff and intervenors in the development of its proposed credit scheme in advance of its next filing.

Q. Why does your calculation of a credit differ from witness Bellini's proposal for a credit for labor against a CIAC?

A. I believe witness Bellini and I differ on how to think about what costs are being caused and avoided by early adopters (in addition to disagreeing about whether a CIAC is appropriate) in a world where all conversions will eventually occur. Witness Bellini approaches the question of conversion CIACs from the perspective of total cost of the group conversion, rather than the marginal cost – that is, the difference in cost between a group conversion and the alternative, which would be many reactive conversions that would happen over a period of time, each requiring a visit by a restoration crew. His proposal to provide a labor credit recognizes that the Company will, eventually, incur labor costs to convert any given HPS fixture to LED, so it might as well cover the labor cost now for any customer prepared to sign up for a group conversion.

This reasoning is sound as far as it goes, but it does not go far enough. In fact, if the customer does not request conversion now, then the Company, sooner or later, is going to have to cover the entire cost of an HID-LED conversion, including the cost of the luminaire, the cost of a truck roll and crew time, various other staff costs (planning, supervision, bill updates, etc.) and administrative and general costs, to name a few. That time will come when the HID fixture fails, in most cases owing to a lamp burnout. Witness Bellini has articulated no underlying rationale for crediting group-conversion customers

for labor costs -- but not all the other conversion costs saved by group conversions -- when assessing what credit should be applied.

I believe the better method is to calculate marginal costs, comparing the cost per fixture of a group conversion project today to the cost per fixture of reactive (post-failure) conversions over an extended period of time. We already have good building blocks to determine these figures, because we know how much DTE charges per light for group conversions and we know how much DTE spends per light to respond to individual outages. Cost of service is lower with group conversions than with reactive conversions – not to mention that group conversions improve reliability by preventing outages that trigger reactive conversions.

Q. Can you illustrate some of the savings that group conversions can deliver compared to the current CIAC that is charged for such projects?

A. In the case of the City of Ferndale's LED conversion project, the net unit CIAC fee DTE assessed was $279.81, calculated as follows:

$418,240 gross project cost + $69,750 DTE contribution = $487,990

$487,990/1,744 fixtures = $279.81 total unit cost recovered through CIAC

We also know how much it costs DTE to respond to a streetlight outage. In Exhibit A-25, Sch O2, we see that the "Outage cost per event" in 2023 was $568. This amount is several hundred dollars higher than the cost of replacing the fixture with an LED as part of a group conversion project.

Cost data from Consumers Energy tends to confirm this finding. Consumers performs vicinity conversions: when a HPS light is reported out, the crew not only converts the non-functioning light to LED but also converts other nearby fixtures to LED even though there

is nothing wrong with them. Consumers witness Dan Schmoekel testifies, "Approximately $253,000 in customer savings has been realized since 2022 through vicinity conversions by reducing non-premise time of field personnel."[29] If it is more cost-effective to convert two fixtures in one trip, as Consumers does, then it is even more cost effective to convert 20 or 30 fixtures in one trip – about the number of conversions that a crew can typically complete in a workday.

Q. If DTE does not assess a CIAC for group conversion projects, won't there be greater demand for group conversions than the Company can keep up with?

A. If so, this would be a solvable problem. A project queue could be established that DTE could work through in an orderly manner. While I might in other circumstances be more concerned with establishing an equitable process for rationing group conversion projects among customers, in this case no such concern is warranted. First, when other customers had to pay to be "first," those who were not volunteering to pay up front for a project will have little basis to object about now having to wait. Second, the customers who still have HPS lights have not responded to various financial incentives and outreach promoting LED conversions for the last ten years; meaning they are less likely to complain about delays in receiving a benefit that now comes without up-front cost to them.

The reason that escalated demand for conversions is properly understood as an opportunity, not a problem, is that it presents the opportunity to get fleet LED conversion done faster and cheaper, while preventing future HPS outages, and transitioning customers to the cheaper LED tariff sooner. Having not paid a CIAC, of course, these customers would not

[29] U-21534 Exhibit MAU-16, U-21585 Consumers witness Schmoekel direct testimony, p. 18, lines 9-10.

receive the LED bill credits I describe above; but their new LED tariffs should still be less than the HPS tariffs they are paying today.

Q. Please summarize your recommendation to the Commission regarding CIAC fees for customer-requested HID-LED group conversion projects.

A. No CIAC should be assessed for HPS-LED conversion projects going forward. The cost of service will be less by converting lights to LED in group projects than by converting them one-by-one upon failure.

Community Lighting Sales Forecast

Q. What adjustment do you recommend making to the community lighting sales forecast as described by witness Bellini?

A. I mostly agree with the forecast but recommend that the Commission update the inputs used to determine reduction to the E1 Option I annual usage to account for lights that are non-operational throughout the course of the year.

Q. Please explain why DTE reduces its sales forecast to account for outages.

A. In case no. U-21297, the Commission adopted MI-MAUI's recommendation to reduce the streetlighting E1-Option I Sales Forecast for Company-owned lights. Until then, street lighting rates assumed that all streetlights were fully operational and using electricity 4,200 hours per year. MI-MAUI objected that streetlight electricity use is drastically reduced when a streetlight is out of service and recommended using the Company's Night Patrol outage rate as a reliable measure of overall outage rate. We also recommended that the Night Patrol outage rate of 3.57% be reduced slightly to account for the small amount of electricity used by HID fixture ballasts when their lamps have burned out. The Commission accepted MAUI's recommendations and ordered a net reduction of 3.25% in the E1-Option

I sales forecast.

Q. Please describe what changes to the forecast you would recommend.

A. I do not recommend any changes in the methodology. However, three key calculation inputs have changed measurably compared to the figures used in case no. U-21297. The updated inputs should be used to recalculate the sales forecast reduction.

Q. Please describe and quantify the three input values that have changed.

A. The first input value that has changed is the Night Patrol outage rate. In 2023, that rate was 4.37%, which is an increase in outages from the 2022 rate used in in case no. U-21297 of 3.57%.[30]

The second input value that has changed is the number of HID fixtures remaining under the E1, Option I rate. DTE has since converted many of those fixtures to LED. It is important to track this change in figuring the sales forecast reduction because the ballasts in HID fixtures use about 15% of normal electricity even when their lamps are burned out, whereas non-functioning LED luminaires use essentially no electricity. Fewer HIDs means fewer ballasts using energy during outages.

The third input value that has changed is the total (unadjusted) electric sales forecast, which declines as LED luminaires replace HID fixtures. I note that I do not recommend any changes based on this input because unlike the two factors above, DTE accounts for this change in its sales forecast adjustment.

Q. Based on these changed inputs, what reduction in the sales forecast for E1, Option I lighting do you recommend?

A. I recommend a reduction of 3,308,045 kwh, equivalent to 4.06% of DTE's unadjusted

[30] DTE Exhibit A-25, Schedule O1.

forecast for E1, Option I streetlights.[31]

Company Preventive Maintenance Programs

Q. What preventive maintenance topics will you address?

A. I will address streetlight post inspection and painting, Night Patrol and underground cable replacement.

Q. What concerns do you have about the Company's proposals for streetlight post inspection and painting?

A. I have concerns that the Company has a history of vastly over-collecting for this area. MI-MAUI members are concerned about the condition of their decorative posts, which are typically located in neighborhoods where aesthetics matter, such as commercial areas with heavy pedestrian traffic. Inspection and painting of posts is necessary to maintain the appearance and condition of posts and guard against the need for more rapid capital investment.

The Company proposes to spend significantly less on inspections and painting ($260,000 total) than the Commission approved in previous cases. Further investigation reveals that in recent years the Company has collected substantially more than half a million dollars for this work that was not spent, as shown in the following table. Calendar years and test years do not align perfectly but suffice for comparison purposes, especially given the large differences.

[31] Exhibit MAU -18, sales forecast outage adjustment worksheet.

	CY2022/U-20561	2023/U-20836	CY2024/U-21297
Approved spend (inspection + painting)	$489,000	$486,580	$718,810
Actual spend	$218,005	$102,886	n/a
Difference	$270,995	$383,694	

Actual spend per U-21534 Exhibit MAU-18, response to MAUIDE-4.28b.

Actual 2024 spending has not been provided, but witness Bellini's explanations of his proposed amounts for the test year in the instant case gives us some clues. He explains that Community Lighting spent less in 2023 than in prior years because wood-pole inspections are now conducted by the Pole Top Maintenance program.[32] Thus, there should be no need for higher post inspection budget going forward.

Regarding post painting, witness Bellini explains that the Company anticipates reduced painting capacity going forward because it now uses one painting contractor instead of the two it used prior to 2024.[33] Therefore, the 2024 amount should be less than the 2023 amount, as should the test-year amount. Based on witness Bellini's testimony and discovery responses, then, it seems reasonable to assume that 2024 inspection and painting costs will be no greater, and possibly less than, 2023 expenditures.

Based on actual historical spending and witness Bellini's explanations, I would normally recommend that the Commission approve spending at 2023 levels plus inflation.

The table above, however, makes it obvious that the Company has already recovered its projected test-year inspection and painting costs several times over by vastly underspending approved amounts over the past several years. Between 2022 and 2023, the Company recovered about $650,000 more than it spent, and reasonable extrapolation

[32] Exhibit MAU-20, response to MAUIDE-6.52.
[33] Exhibit MAU-21, response to MAUIDE-6.53.

supports an estimate that will recover at least $500,000 more than it will spend in 2024. In total, then, through 2024 the Company will have recovered at least $1,150,000 more than it will have spent on inspections and painting – and that is looking back only three years. Another way to look at it is to observe that the Company has spent only about 25% (~$425,000/$1,694,390) of what it has recovered from customers to pay for inspections and painting from 2022-2024.

Therefore, my recommendation to the Commission is that it disallow any recovery of inspection and painting costs in the test year, based on evidence in the record that the Company has already been paid to do that work. However, the Commission should also make clear that DTE must continue to inspect and paint posts at the historical pace, if not more to avoid further disallowances.

Q. Do you have any other recommendations for the Commission pertaining to post inspection and maintenance?

A. Yes, I do. First, the Commission should clearly state that the Company must implement robust inspection and maintenance programs. It is not acceptable for the Company to maintain assets poorly and then incur premature capital replacement costs. Specifically, the Commission should instruct DTE to state annual targets for inspections and painting and to report on its performance to those targets in rate filings.

Second, the Commission should make clear that it will not pay twice to perform important O&M once. Given the Company's dramatic failure to spend recovered money on maintenance of decorative lamp posts that customers paid an additional amount for, and which are highly visible in the community, I recommend that the Commission order the Company to file as part of their next rate case a report on actual costs with amounts

recovered in rates, looking back five years.

Q. DTE proposes to spend significantly more on Night Patrol in the projected test year than in 2023. Do you support this change?

A. Yes, I support increasing the scope of Night Patrol. Night Patrol is an innovative program that has identified many outages before they are reported by community members, allowed for quick restoration of service, and given the Company valuable data to understand causes of outages. Outage occurrences and durations have been a long-standing challenge for the Company, and I believe that Night Patrol is a key element in helping the Company turn the corner and improve overall reliability.

Q. What concerns do you have about the Company's underground cable replacement program?

A. The Company has not provided reliability or cost data to justify this program. The Commission should disallow the proposed spending and make clear what information the Company should provide if it chooses to propose this program in future rate cases.

The first waypoint in this analysis should be the Company's plan for improving streetlight reliability as articulated in its Distribution Grid Plan. As I noted in my comments dated March 15, 2024 and submitted to docket U-20147, DTE makes absolutely no mention of streetlights or streetlight cable replacement in its DGP.[34] As a general proposition, the Commission should not authorize distribution system investments that have not been incorporated as part of DTE's DGP.

That said, I commend the Company for exploring preventive maintenance approaches that may prevent future outages. Preventive replacement of underground cable holds the

[34] Exhibit MAU-22, MI-MAUI comments in U-20147 docket in re DTE DGP.

promise of preventing outages that impact multiple lights and last longer than other outages.

Replacing underground cable is expensive, however, and prioritization should be data-driven. This is an analysis that the Company should have conducted in its DGP but did not; nor has it done so here. Witness Bellini states, "The cable replacement program uses the following criteria to determine selection and prioritization of projects: 1) age of cable, 2) pedestrian conflict (level of pedestrian traffic), 3) recurring outages, 4) number of lights on the circuit, and 5) type of road."[35] The Company provides no data to support this prioritization, and evidence that is in the record suggests that it does not even have the relevant data necessary to perform this prioritization. For instance, the Company has previously maintained it does not have data on how many lights are impacted by outages, so it will not have the historical information necessary to perform this prioritization.

Presumably, the best predictor of future outages is past outages, especially those that occur spontaneously (e.g., not from third-party strikes). The Company's OMS might be queried to find areas that are experiencing the most spontaneous cable breaks, but the Company has previously indicated that it is unable to classify outages by cause, including the ability to distinguish between spontaneous breaks and third-party damage.

It is also plausible to suppose that old cable is more likely to break and therefore ought to be prioritized for preventive replacement, but this depends on knowing where the old cable is located and showing a correlation between age and failure rates. Again, this hypothesis is testable, but there is neither data nor analysis in the record.

Witness Bellini states other criteria for replacing underground cable preventively include

[35] Exhibit MAU-23, response to MAUIDE-4.26.

road type, pedestrian traffic, and number of lights on the circuit but makes no logical connection between them and light failures, nor does he provide any data or analysis.

Witness Bellini also argues that preventive maintenance is more cost-effective than reactive repairs, an appealing proposition that may well be correct, but one without any underlying quantified analysis.

Q. What would make the case for preventive cable replacement more persuasive?

A. A data-driven approach would demonstrate that:

- Underground cable with certain characteristics, ages, installation types or locations is prone to repeated and reasonably predictable failures.
- The Company can identify where the failure-prone cable is installed.
- Failures of this type account for a disproportionate number of outage days, considering the number of lights impacted and the time it takes to restore service.
- Replacing the cable altogether costs less than repeatedly repairing it and prevents outages.
- To whatever extent preventive cable replacement is not strictly cost-effective, the Company can quantify the reliability benefits customers will realize from the investment.

Based on witness Bellini's descriptions of the new outage management system and the Night Patrol database, the data needed to make this case may be available for the next rate case, in a way the data is unavailable today.

Q. What do you recommend the Commission order regarding replacement of underground street lighting cable?

A. The Commission should not include spending on this program in the revenue requirement.

Consonant with my comments on DTE's DGP, filed in case no. U-20147, the Commission should require the Company to support its plans for this part of the distribution grid in its DGP.

If the Commission does not wish to instruct the Company to amend its DGP, it should leave the door open for the Company to support its cable replacement plans in a future rate filing. I have testified repeatedly about the Company's inferior performance with streetlight reliability. I welcome investments that can be shown to improve that performance. Spending based on hunches, when those hunches can be tested using straightforward analyses, is not prudent.

Community Lighting Outage Restoration Activities

Q. What is your assessment of DTE's streetlight outage restoration performance?

A. Both outage frequency and outage duration are declining. However, it is likely that reductions in outage counts are not attributable to the Company's outage response efforts. Because the Company's spending on outage restoration activities has been growing rapidly, the Commission should require the Company to provide additional data to demonstrate cost effectiveness.

Q. Is DTE achieving its target for outage durations?

A. No, it is not. In 2023, average outage duration was 4.17 days, continuing a downward trend from 2021's peak of 5.22 days.[36] The Company is still about 39% over its previously stated target of 3.0 days for outage durations and well above its average for 2017-2020 of 3.57 days – despite greatly increased spending. The improvement we see has come since 2021,

[36]Bellini, Exhibit A-25, Sch O1. I note that witness Bellini's testimony (RAB-17, line 21) states that 2022 performance was 4.2 days, but the exhibit shows 4.7 days. I assume that witness Bellini's testimony refers to 2023 performance.

which is not a useful baseline year for measuring performance. When we compare to a more useful pre-pandemic performance baseline, we are not seeing remotely the kind of performance improvement we should expect from the Company's greatly increased spending in this area. In fact, from a pre-pandemic baseline, performance has worsened. Furthermore, outage durations data for 2023 are derived from less than three months of data, from some point in October through December.[37] Months with the longest average streetlight outages tend to be those when distribution system outages are most widespread and crews de-prioritize streetlight repairs in favor of restoring power to buildings. Outages occur at all times of the year, of course, but generally the worst periods are late summer and winter, not the fall months from which the 2023 outage durations data were extrapolated. Thus, there are grounds to suspect that the reported durations understate the true full-year average.

Q. What is the company's target for outage durations?

A. I note that witness Bellini's testimony no longer includes a stated target for outage restoration time, as it has in the past. Witness Bellini's testimony in case no. U-21297 stated an outage duration target of 3.0 business days.[38]

Q. Please summarize the Company's spending trend on outage restoration activities.

A. The average outage cost per event has risen, almost without interruption, from $221 per event in 2017 to $568 per event in 2023.[39] Total outage restoration costs have increased over that period from $4.5 million to $9.4 million. Spread over approximately 200,000 lights, that increase equates to about $25 in increased annual cost per light for outage

[37] Exhibit MAU-24, response to MAUIDE-4.24.
[38] Exhibit MAU-25, U-21297, Bellini direct testimony RAB-18, line 24.
[39] Bellini, Exhibit A-25, Sch O2.

restoration, the majority of which is capitalized. This increase in costs is significantly impacting the cost of service and has not been adequately explained.

Q. Why do you state that reductions in outage counts are not attributable to the Company's outage restoration efforts?

A. All the reductions in outage counts can be attributed to increased deployment of LED luminaires, because they do not require bulb replacements every eight years or so. The Company had about 71,000 fewer HID streetlights (and 71,000 more LEDs) in 2023 than it had in 2017.[40] On average, one-eighth of those decommissioned HIDs would have had reportable outages each year caused by lamp failures – accounting for roughly 9,000 of the reported outages in 2017. Yet Mr. Bellini reports that total outage events went from 20,670 in 2017 to 16,544 in 2023 – a reduction of only 4,026 events.[41] Increased deployment of LEDs alone should have led to 5,000 fewer outages than were reported in 2023. The Company's increased spending on outage restoration should have contributed an additional reduction in outage events on top of the reduction attributable to LEDs, but we see no evidence of any such contribution – in fact, we see the opposite.

Except when the Company replaces failed Mercury Vapor fixtures with LEDs, customers pay for HID-LED conversions. A reasonable interpretation of the data available is that the Company's greatly increased spending on outage restoration has contributed nothing to the observed reduction in outage events. The *entire* reduction in outage frequency – and then some – is likely attributable to out-of-pocket spending via CIACs by customers on LED conversions.

[40] Bellini testimony, Table 2, RAB-8.
[41] Bellini, Exhibit A-25, Sch O2.

Q. Why do you estimate the contributions of LEDs to the observed reduction in outage counts rather than using actual outage data?

A. The Company has not provided data on root causes of outages, so we cannot isolate outages caused by lamp and fixture failures from other causes. My understanding is that the new OMS described in witness Bellini's testimony will greatly increase the Company's ability to track and report on root causes and their costs.

Q. What do you recommend the Commission order with respect to DTE's outage restoration costs?

A. I recommend that the Commission approve the Company's proposed costs. Reliability is the biggest concern of most streetlight customers and nobody wants to see a decline in performance. The decision to deploy the new OMS is particularly welcome, however, because of the impact it could have on better targeting spending.

Simply put, current data does not demonstrate that the Company's spending or efforts are effective – much less cost-effective. That is, the Company provides annual outage occurrence and duration data but cannot demonstrate any association between its programs and changes in those metrics. Therefore, I recommend that the Commission order the Company to provide detailed outage event data with its next rate case filing, covering both customer-reported outages and Night Patrol outages. Reporting should be organized by root cause and should include average restoration cost and average duration per root cause. Reporting should also include detailed data on long-duration events, organized by cause of the delay in restoration. Rather than being more prescriptive than this in its order, I recommend the Commission order the Company to provide a proposed reporting scheme within three months of its final order in this case, for review and discussion with Staff and

intervenors. The proposal should provide a proposed taxonomy of root outage causes, causes of delays in restoration, cost breakdowns and other data to be provided.

Q. Witness Bellini proposes a plan for periodically reporting outage data to streetlight customers. Do you support his proposal?

A. Yes, I do. MI-MAUI met with DTE and Commission staff and reviewed the Company's proposal. We asked questions and made several recommendations, and we received reasonable responses from the Company. We consider this a valuable and important step forward on what we hope will be a more strategic and informed approach to tackling streetlight reliability issues.

Q. Witness Bellini proposes to narrow the scope of the Commission's order in case no. U-21297 by providing outage reports only to E1, Option I customers rather than all E1 customers. Do you support this change?

A. Yes, I do. I agree with witness Bellini's reasoning on this point.

Q. Do you support the timeline witness Bellini proposes for sending outage reports to customers?

A. Witness Bellini's testimony does not commit to a date by which the Company will begin to send outage reports, evidently because of uncertainty about the timeline for achieving full operation of the new OMS system he describes. However, Mr. Bellini's testimony also estimates that the OMS will be fully functional by Q2 or Q3 of 2024, which time is already upon us. Therefore, I believe it would be reasonable for the Commission to include in its order a date certain by which the Company should provide initial reports.

Specifically, I recommend that the Commission order the Company to provide the required quarterly reports to its largest customers for Q3 and Q4 of 2024 no later than January 31,

2025, and thereafter to comply with the reporting schedule specified in its U-21297 order.

Q. Would you recommend that the Commission put any stipulations on its approval of the Company's proposal?

A. Yes. Currently, the Company asserts that it has the ability only to report outage events. Each event may impact more than one streetlight. For example, an underground conductor strike may interrupt electric service to multiple lights. The Company explains that its outage management system currently does not have the ability to track how many lights each event impacts. Thus, while the Company reports 12,264 "standard events adjusted" in 2023,[42] the number of streetlights out of service during those events may have been, and likely was, significantly higher.

While I understand why there may be a technical issue with reporting the number of lights that have experienced outages in any given period, it is important to recognize that customers see the number of lights that are out, not some common root cause. They are unlikely to feel confident in the integrity of a report that represents that (for example) six lights out is "1" outage.

Mr. Bellini has described the Company's efforts to improve its outage management system and it is my understanding that the Company anticipates being able to report outages on a "per light" rather than "per event" basis soon. This capability is one of the key factors in MAUI's support for the OMS. Therefore, I recommend that the Commission order DTE to propose a specific timeline for reporting on outages per light rather than per event as part of its next rate filing, or to justify why it cannot do so.

[42] Bellini Exhibit A-25, Sch O1.

Community Lighting Operations & Maintenance and Capital Expenditures

Q. Do you support witness Bellini's proposed O&M expenditures?

A. No, I do not. The Company is proposing an unjustified increase in spending on staff. Per my testimony about preventive maintenance activities above, the Company is also proposing unjustified costs for post inspection and painting.

Q. What change in staff O&M spending does the Company propose?

A. In its order in case no. U-21297, the Commission approved staff O&M spending of $1,279,807, and in this case proposes spending of $1,800,000, an increase of about $520,000 or 41%.

Witness Bellini explains that the increase is meant to cover new hires for unfilled positions, inflation and increase in administrative costs inclusive of using contractors.[43] When invited to explain the changes in number of FTEs broken down by title and or classification, witness Bellini provided only historic and projected total head counts showing that 2025 staffing will be about [redacted] lower than 2024 and [redacted] lower than 2021.[44] The Company does not explain why it needs a 41% increase in the staff budget when it will have fewer staff in the test year than in the past. A significantly higher staffing budget is being proposed for a team that is projected to do fewer inspections and respond to fewer outages than in the past. The following table compiles the Company's proposed O&M spending in the instant case to the levels approved in the Commission's order in case no. U-21297 and to my recommendations for test-year spending.

[43] Exhibit MAU-26, Bellini response to MAUIDE-6.55.
[44] Exhibit MAU-28, Bellini NDA response to MAUIDE-6.56.

	O&M 2024 Rate Case Test Period	U-21297 approved spending	MI-MAUI test-year recommendation
Streetlight Inspection	$130,000	$334,383	$0
Streetlight Painting	$130,000	$384,427	$0
Night Patrols	$400,000	$384,427	$400,000
Cancelled Projects/Other	$60,000	$80,252	$60,000
Outage Restoration	$5,653,000	$7,490,173	$5,653,000
OPL Outage Restoration	$665,000	$802,519	$665,000
Gross direct cost of O&M projects	$7,038,000	$9,476,181	$6,778,000
Supervisory & Administration	$1,800,000	$1,279,807	$941,950
Supv & Admin as % of direct project costs	25.6%	13.5%	13.9%
Capitalization Credit	($4,750,000)	($6,921,723)	No recommendation
Damage Claims	$0	$0	
Net Total	$4,088,000	$3,834,265	No recommendation

I recommend that the Commission approve $6,778,000 on direct O&M project spending in the test year, with the only difference from the Company's proposal being my proposed disallowance of any further cost recovery for inspections and painting.

I recommend that the Commission approve Supervisory & Administration spending of $941,950. As the table shows, this is the same ratio of staff budget to direct project cost as the Commission approved in case no. U-21297, plus a 2.9% adjustment for inflation.

I make no recommendation concerning capitalization credits, and consequently no recommendation about total net spending on O&M.

Q. Do you have any other comments on the Company's proposed Community Lighting O&M?

A. Yes, I do. I support robust O&M with emphasis on outage prevention. I see outage prevention as even more important with streetlights than with other rate classes, for two reasons. First, streetlight outages get reported slowly, which is why Night Patrol finds so many outages that have not yet been reported by customers. Second, streetlight outages are

at the bottom of the restoration priority list – rightly so: it is more important to restore power to buildings. If we de-prioritize restoration, allowing known streetlight outages to wait until crews become available after serving higher priorities, then at least we should take strong steps to prevent those outages happening to begin with.

Regrettably, the Company has greatly underspent its inspection and painting budgets over the past several years. It would be imprudent to support recovery of O&M costs that history shows the Company will not incur. I would support an O&M plan that provided specific targets for inspections and painting, and I would support an O&M budget grounded in evidence that the spending was likely to improve reliability. For now, though, in my view the Company has already been paid in advance for the next several years' worth of inspections and painting at historic levels, has experienced decreasing reliability, and should not be allowed to recover additional money until it can reconcile how it has used funds it already received.

Q. Do you support the Company's proposed Community Lighting capital expenditures?

A. First, I renew my objection to the Company's failure to address street lighting in any way in its Distribution Grid Plan. I recommend that the Commission order DTE to address its plans for all Community Lighting services in its next DGP, where it may be analyzed with the same level of rigor as other distribution system investments.

My objection notwithstanding, I support the costs itemized in Exhibit A-12, Sch, B5.5 except for the underground cable replacement program. Per my testimony above, the Company has failed to show that this program is cost-effective. The Commission should disallow this expenditure while also inviting the Company to propose this program in a future filing with appropriate cost-effectiveness data and analysis. Total test-year capital

expenditure for Community Lighting should therefore be $15.575 million.

LED Luminaire Selection Methodology Specific to HID to LED Conversions

Q. Please summarize your concerns about DTE's practices and costs for conversions of HID streetlights to LED.

A. I am concerned that the Company continues to install LED luminaires that are unnecessarily bright and drive up the cost of service.

In case no, U-21297, the Commission found that the Company's costs for choosing LED luminaires to replace HID fixtures were unreasonable. The Commission noted that the Company significantly exceeded its manufacturer's guidance for choosing LED replacements for each kind of HID fixture, without providing any other evidence that its conversion standards are reasonable.

Q. What is DTE's proposal in this case pertaining to conversion costs?

A. The Company is providing new evidence and arguments that purport to justify its conversion practices and costs and asks the Commission to allow the Company to recover the costs that were disallowed in case no. U-21297.

Q. Do you support the Company's proposal?

A. No, I do not. The Company has failed to meet the clear standard that the Commission set in case no. U-21297, which is to demonstrate that its costs are consistent with reasonable efforts to comply with roadway lighting standards.

Instead, the Company disavows that its objective is to comply with roadway lighting standards when it converts HID streetlights to LED and asserts that it is therefore reasonable for it only to match performance of the incumbent HIDs when choosing LEDs. It then provides expert opinions that its methodology for matching LEDs to HIDs is

technically sound. Here, the Company is making the perfect the enemy of the good, claiming that since complete compliance with a standard of roadway lighting would be burdensome due to the need to develop new lighting designs, it should be permitted to disregard the standards entirely when more closely approximating the standards would lower customer costs. The Commission should sustain its prior disallowances.

Q. Has DTE consistently taken the position that new lighting designs for LED streetlights would be an added expense?

A. No. When MI-MAUI first raised the issue that DTE's standard LED light replacements were too expensive and too bright, witness Bellini opposed those proposed revenue reductions in part because he testified that the Company's light selection would provide the opportunity for cost reductions through redesigns: "[u]sing higher wattage fixtures means fewer poles and luminaires are used which is economical and reduces the need for additional infrastructure."[45] However, when pressed, the Company admitted that its practice was to replace all poles with HPS fixtures with LEDs rather than undertake the necessary redesign to determine if fewer poles could be used. DTE's purchase of higher wattage fixtures, therefore, does not reduce the need for additional infrastructure, or the costs to customers, in practice.

Q. Does the ability of customers to depart from DTE recommended wattage lights address your concerns about higher costs of the DTE recommended lights?

A. No; this argument is a red herring. The Company makes it inconvenient and expensive for customers to choose materials other than the Company's default choices and asks customers to agree that other choices will not comply with lighting standards, without

[45] Exhibit MAU-27, U-20836 Bellini Rebuttal excerpt.

providing analysis regarding whether their choices are compliant or not.

Q. DTE witness Bellini makes four recommendations regarding HID-LED streetlight conversion costs in his testimony. Do you support his recommendations?

A. No, I disagree with witness Bellini's recommendations.[46] I will summarize my concerns first, then develop each more fully further on.

Q. What is witness Bellini's first recommendation and why do you disagree with it?

A. Witness Bellini argues it would be prudent for the Company to continue utilizing its current default LED replacements for certain HID streetlight fixtures, rather than the LEDs recommended in a crossover chart provided by its supplier, Leotek, which is not currently available. Witness Bellini argues that expert analyses provided in his exhibits and workpapers support the Company's choices of standard LED replacements for its incumbent HID fixtures. The Company's testimony does not do so, for the reasons summarized below and explained in more detail in my testimony.

In U-21297, the Commission sought evidence that the Company's preferred luminaires were necessary to comply with streetlighting standards, and without such evidence, denied cost recovery for the needlessly expensive lights. The expert assessments that witness Bellini provides vouch for the comparability of the Company's standard LED luminaire replacements for common HID fixtures, but do not find that this replacement is necessary to meet standards. Moreover, the modeling data his experts provide belies the Company's contention that such lights are necessary. The Company's workpapers provide modeling results that show its default LEDs usually and often significantly deliver more light than standards indicate is needed. The modeling results also show that using other, less

[46] Bellini testimony, p. 35, line 5 – p. 36, line 24.

expensive LED models would yield better cost and lighting results.

Q. What is witness Bellini's second recommendation regarding HID-LED conversions and why do you disagree with it?

A. Witness Bellini describes the Company's current and proposed practices for informing customers about its compliance with roadway lighting standards. The Company proposes "explicitly informing the customer in the contract and during discussions that the customer has the choice to select another LED at their discretion and confirmed in the municipal conversion agreement."[47]

I support this proposal as far as it goes, but it does not go far enough. Witness Bellini's proposal is insufficient to meaningfully empower customers and lead to greater accountability for quality of conversion practices. Empowered customers need reliable, sufficient, and comprehensible information and the ability to act on that understanding. That is not the case here. Checkbox-style disclosure that standards will not be met is insufficient because customers are unlikely to understand the implications of that disclosure. Customers cannot rely on DTE's information, either: I will show that DTE does not consider reasonable alternatives, much less present these more cost-effective options to customers. It makes little sense to make customers responsible for a decision they expect DTE to have the technical capacity to make, and most customers will depend on the Commission to confirm the reasonableness and cost effectiveness of standard offerings. Finally, customers' freedom of choice is significantly constrained: DTE makes alternative light choices more expensive and inconvenient for the customer.

This is a textbook example of the need for regulation. When customers have a difficult

[47] Bellini testimony, RAB- 36 starting at line 6.

time gathering and understanding technical information, and have no ability to choose different providers, then the solution is to ensure the choices provided are reasonable and prudent, without needless built-in costs.

Q. What is witness Bellini's third recommendation regarding HID-LED conversion practices and costs and why do you disagree with it?

A. Witness Bellini states that DTE would be amenable to a staff-facilitated technical workshop with various stakeholders to examine the Company's conversion standards and costs.[48]

I would not support convening of a technical workshop at this time. If the Commission were presented here with relevant technical evidence about which experts could reasonably disagree, then convening a technical collaborative might make sense. While we can glean some evidence about compliance of the Company's LED installations with the ANSI/IES RP-8 standards, witness Bellini's testimony and the consultants' reports focus on the equivalency of DTE's HID-LED conversions, not to compliance with standards. Once DTE presents comprehensive and credible information in a rate case filing about its efforts to comply with roadway lighting standards, supported by comparative cost data, which intervenors can scrutinize and reply to, then the Commission can choose whether to decide the issue then and there or refer it for technical study. Moreover, since DTE's lighting choices are very different than those of other Michigan utilities, there is little evidence that the issue here is truly technical as opposed to a continuing effort to attempt to increase capital spending beyond reasonable and prudent levels.

Q. What is witness Bellini's fourth recommendation and why do you disagree with it?

[48] Bellini testimony, RAB-36 starting at line 6.

A. Witness Bellini asks the Commission to revisit its decision in case no. U-21297 to disallow $5.8 million in LED gross plant.

I disagree because witness Bellini has not met the clear standard that the Commission articulated in case no. U-21297. The Commission wrote, "…the company is simply guided by the original lumen output, which does not equate to compliance with the relevant standards and is based on an outdated technology that is undergoing replacement."[49] Rather than attempting to show that the Company makes reasonable attempts to comply with relevant standards, witness Bellini declares, without offering any evidence, that the standards are impractical for HID-LED conversions. Instead, he attempts to demonstrate how well the Company performs a function that the Commission has stated is not relevant to the task at hand: matching the *original* lumen output. Not only does this ignore testimony offered about output, it sidesteps the question of whether that original output was appropriate in the first place.

My argument for disallowance does not rest solely on DTE's failure to respond to the Commission's prior order. It is based on evidence that shows DTE does have cost-effective options for improving compliance of its HID-LED conversions with roadway lighting standards, and that these options are used by comparable utilities here in Michigan.

Q. Please outline your argument against witness Bellini's first recommendation, regarding prudency of DTE's practices for choosing LEDs to replace each type of HID streetlight.

A. My argument has two key elements.

[49] U-21297 order, p139.

First, witness Bellini has not addressed the Commission's concerns stated in its U-21297 order. Rather, he tries to move the metaphorical goalposts by focusing his testimony on comparability of LEDs to HIDs. He also inappropriately delegates responsibility for satisfying roadway lighting standard to customers, obfuscating the technical role the Company necessarily plays in lighting conversion projects and the barriers customers encounter when they want to diverge from DTE recommendations.

Second, his attempt to move the goalposts is ill-founded. He simply asserts that meeting roadway lighting standards is unreasonable for HID-LED conversion projects, without providing any supporting data. The modeling data he does provide proves the opposite case: the Company could come into closer compliance with roadway lighting standards and save customers money while doing it.

Q. In its U-21297 order, the Commission discussed the Leotek conversion chart, which was congruent with your interpretation of a key lighting standard (ANSI/IES RP8) in contrast to DTE's interpretation. Is that chart discussed in DTE's current testimony?

A. No, because Leotek has removed that chart and now offers no conversion advice.

Q. Should the removal of the conversion chart by Leotek excuse DTE from discussing why its preferred but more expensive lights are necessary to meet lighting standards?

A. No. In its U-21297 order, the Commission did not say that DTE must follow the manufacturer's guidance; it merely noted that DTE failed to justify why it was departing from that guidance, without providing any evidence that its preferred approach yields better results. If DTE cannot rely on the manufacturer's guidance to show its brighter lights are needed to comply with roadway lighting standards, then it must find another way to do so,

for example through the modeling exercises it offers as evidence in this case.

Q. Does DTE put forward evidence in this case that its brighter lights are needed to comply with ANSI/IES RP8 standards when converting existing HPS streetlights?

A. No. DTE's position in this case is that it would be "impractical and costly to conform to current ANSI/IES RP8 lighting standards for pre-existing lighting systems" because older systems would need extensive reconfiguration inclusive of work such as pole relocations and rewiring of the overhead and underground system cable. [50] Therefore, it continues to install an LED that is as bright at the HPS was projected to be at the start of its life, without first analyzing whether lower wattages would suffice.[51]

Q. Would lower-wattage lights better approximate lighting standards without extensive redesign of older systems, and save customers money?

A. Yes, in most cases I believe they would, for several reasons. The expert analyses provided by witness Bellini, support this contention – DTE could more closely approximate roadway lighting standards without redesign by installing LED luminaires from the same product line but with lower wattages.

Q. Can we assume incumbent HID lights at their brightest were compliant with roadway lighting standards?

A. No. Even if original designs did meet lighting standards at the time (which is itself an assumption that we have no data to support), lighting standards, designs and technologies have all changed over decades.

Second, data available suggest that DTE's HID fixtures vary greatly with respect to their

[50] Bellini testimony RAB-25, lines 12-18.
[51] Bellini testimony RAB-25, lines 12-18.

performance against standards. The modeling done by Mr. McLean, described in Exhibit A25, Schedule O5 and documented in his workpapers submitted by Mr. Bellini, shows wide variance in lighting provided by 100w HPS fixtures compared to standards, and consistent overlighting of areas served by 250w HPS fixtures.[52]

Although Mr. McLean's narrative report primarily addresses whether DTE's choices of LED luminaires reasonably match the HID fixtures they replace (which I note was never in dispute in U-21297), his workpapers also model performance of the incumbent HID fixtures and show the ANSI/IES RP-8 standards for the roadways he modeled. Data in the tables below is copied from Mr. McLean's workpapers, with the only addition being a simple calculation to show how each original HPS light modeled stacks up against the lighting standards Mr. McLean identified for each location. Note that this table, and others to follow, provide both luminance and illuminance values. For straight roadways, the ANSI/IES RP-8 handbook prefers use of luminance. I focus my discussion on luminance but provide illuminance values for reference.

For the roadways labeled 100A through G (originally served by 100w HPS fixtures), modeling shows that average luminance varied considerably with respect to the standards. Notably, Roadway 100A provided 240% of the standard, Roadway 100D provided only 85% of standard and Roadway 100E provided 165~~0~~% of the standard. Choosing LED replacements based on HIDs that performed very inconsistently with respect to standards, but overlit the roadway in the majority of modelled intersections, is not prudent practice.

[52] Bellini Exhibit A-25, Sch O5.

DTE ID	Surface	Road Type	100W HPS Avg Lum	100W HPS Avg Ill
A,B,C,F,G	IES Standard		0.3	0.4
D,E	IES Standard		0.4	0.6
100 A	R3	Local	0.72	0.87
			240%	218%
100 B	R1	Local	0.43	0.42
			143%	105%
100 C	R1	Local	0.51	0.49
			170%	123%
100 D	R3	Collector	0.34	0.45
			85%	75%
100 E	R3	Collector	0.66	0.84
			165%	140%
100 F	R3	Local	0.33	0.39
			110%	98%
100 G	R3	Local	0.35	0.46
			117%	115%

Data source: Witness Bellini's Work Paper H - Application Performance Results 100 HPS All LED to HPS 11 11 22. Note: revision corrects Road Type for 100 A from "Unspecified" to "Local"

Turning to the roadways formerly lit by 250w HPS fixtures, we see that Mr. McLean's modeling found all modelled roadways to be drastically overlit by the HPS fixtures per standards, providing 266~~16~~% to 314% of the average luminance standard.

DTE ID	Surface	Road Type	250 HPS Avg Lum	250 HPS Avg Ill
A,F	IES Standard		0.80	1.20
B,C	IES Standard		0.50	0.70
250 A	R3	Collector	2.22	2.98
			278%	248%
250 B	R1	Local	1.36	1.29
			272%	184%
250 C	R1	Local	1.57	1.51
			314%	216%
250 F	R2	Collector	2.13	2.94
			266%	245%

Data source: Witness Bellini's Work Paper J - Application Performance Results 250 HPS All LED to HPS 11 11 22. Note: revision corrects Road Type for 250 A from "Unspecified" to "Collector"

Thus, DTE's own expert results indicate it is not sound to assume that the original lights complied with relevant standards, so matching their initial output will not be a good predictor of the necessary wattage, just as I argued in U-21297. At least one expert the Company engaged stated explicitly that the analysis the Company asked it to perform

contained the assumption that past HPS lighting levels were appropriate: "It is noteworthy that this method of comparing to incumbent technology assumes that the existing technology does not over- or under-light the roadway."[53] That is an assumption which the DTE experts' modeling shows is unsound.

Q. If local governments have important fiscal, social, and environmental goals impacted by street lighting, why do they not simply exercise their power as customers to have DTE install different lights?

A. Customers with the resources to devote staff engineering time to selecting streetlights, the ability to warehouse streetlighting stock, and the upfront cash necessary to meet the CIAC can depart from standard offerings. There are very few municipalities that have the staffing and financial resources to make departing from standard offerings an accessible option.

Q. How does DTE describe lighting standards to customers considering alternative models?

A. DTE's HID-LED group conversion proposals to customers regularly include a checkbox asking the customer to agree it has been told the design does not meet roadway lighting standards. Customers are not informed by the Company or ever asked to certify that it understands that current lights may *also* not meet roadway lighting standards, and that overlighting is a more common non-compliance result than underlighting in DTE's own modelling. When DTE moves to a system of automatically replacing failed HPS lights with LEDs, as witness Bellini proposes in this case, this problem will become more acute because there will be no dialogue or sign-off with the customer for the Company's

[53] Bellini Exhibit A-25, Sch O9, "Review of the DTE Energy Luminaire Selection Process," by Prof. Ronald Gibbons, p3.

conversion standards.

Second, DTE makes it expensive for customers interested in departing from the Company's streetlight models. The Company applies additional fees for "special order materials," including LEDs with different wattages or color temperatures than DTE usually uses. The Company requires the customer either to pay a stocking fee or keep special order materials on hand themselves when they select a non-standard offering.[54] To the instant point, this practice demonstrates that the Company's policies make it impractical or infeasible for customers to choose luminaire specifications that comply better with ANSI/IES RP-8 standards than the Company's default choices, and thus it is all the more important that the Commission continue to deny recovery when the standard lights provided are more expensive to purchase and operate than is necessary. A quick review of spec sheets show that it is not difficult to find or procure luminaires of different wattages, optics, and color temperature from DTE's standard offerings, and thus it would not be difficult for the Company to adopt a new, more cost-effective model that responds to customer feedback.

I will discuss how this standard should apply to luminaire wattage choices, optics, and color temperature.[55]

~~**Q. Does DTE have a standard offering LED with a color-correlated temperature recommended in the ANSI/IES RP-8 standard?**~~

~~A. No. DTE stocks luminaires with CCT of 4,000k. The ANSI/IES RP-8 standard recommends luminaires around 3,000k on highways to improve driver visibility and reduce glare. The standard also states that streets may have a wider range depending on the specific~~

[54] Exhibit MAU-29, response to MAUIDE-4.20.
[55] Exhibit MAU-30, response to MAUIDE-5.47, Leotek GCJ_J Specs.

~~application. Furthermore, lower-temperature lights are generally preferred by customers and can reduce obtrusive light. The City of Ann Arbor recently polled residents on LED CCT options and found a strong preference for 3,000 or 2,700k lights rather than 4,000k.[56] Lower-temperature lights, finally, emit less energetic photons, which are less likely to reflect off incident surfaces and create obtrusive light problems such as glare and sky glow. In short, DTE's standard offering LED not only is of a wattage that is likely to over-light compared to the standard, the Company also fails to offer a standard-order light that conforms to the color temperature preferred by ANSI/IES RP-8 and customers.~~

Q. Has DTE provided any evidence directly responsive to the Commission's stated focus on compliance with roadway lighting standards?

A. Yes, it has, and that evidence undermines the Company's testimony. As I have already shown, the Company's own workpapers reveal that incumbent HPS fixtures do not consistently comply with roadway lighting standards, and most often exceed those standards. The modeling also shows that the Company's criteria and method for matching replacement LED luminaires to incumbent HID fixtures usually results in illumination above, and often well above, the standards.

None of these data, however, come forth in the exhibits or testimony offered by the Company, but rather become evident only upon close examination of witness Bellini's workpapers. Witness Bellini's testimony is concerned only with demonstrating that the Company has a robust method for matching LED luminaires to the HPS fixtures they replace. This was never disputed by MI-MAUI; the dispute was whether this method resulted in over-spending, which it does and continues to do, a conclusion the work done

[56] ~~Exhibit MAU-31, City of Ann Arbor webpage for LED conversion project.~~

by the Company's own lighting experts supports.

Q. What do the modeling results show happens when 58w LED luminaires are substituted for 100W or 250W HPS lights – would similar overlighting occur when compared to the HPS lights that they replace?

A. The most common result is significant exceedance of the standards. I reach this conclusion by comparing Mr. McLean's modeling of LEDs over the various roadways to the lighting standards he found apply to each of them. Mr. McLean modeled five local roadways for 58w LED luminaires and found they would average 188% of the luminance standard, varying from 150% to 313%. Mr. McLean modeled another two collector roadways for 58w LED luminaires and found they would provide 113% and 218%, respectively, of the luminance standard.

			58.4W LED		37W LED	
DTE ID	Surface	Road Type	Avg Lum	Avg Ill	Avg Lum	Avg Ill
A,B,C,F,G	IES Standard		0.3	0.4	0.3	0.4
D,E	IES Standard		0.4	0.6	0.4	0.6
100 A	R3	Local	0.94	0.93	0.70	0.75
			313%	233%	233%	188%
100 B	R1	Local	0.52	0.44	0.43	0.39
			173%	110%	143%	98%
100 C	R1	Local	0.59	0.52	0.46	0.42
			197%	130%	153%	105%
100 D	R3	Collector	0.45	0.48	0.32	0.37
			113%	80%	80%	62%
100 E	R3	Collector	0.87	0.9	0.64	0.71
			218%	150%	160%	118%
100 F	R3	Local	0.45	0.4	0.36	0.36
			150%	100%	120%	90%
100 G	R3	Local	0.46	0.5	0.33	0.38
			153%	125%	110%	95%
Total	*Average*		*188%*	*133%*	*143%*	*108%*
A,B,C,F,G	*Average*		*197%*	*140%*	*152%*	*115%*
D,E	*Average*		*165%*	*115%*	*120%*	*90%*

Data source: Witness Bellini's Work Paper H - Application Performance Results 100 HPS All LED to HPS 11 11 22.

Mr. McLean's modeling also shows that DTE's preferred 136w LED replacement for the

250w HPS fixtures delivers, on average, 317% of the average luminance standard (see table). In other words, the modelling predicts the Company's preferred LED results in the average street will be more than three times as bright as design standards recommend.

			136W LED		111W LED		89W LED		72W LED	
DTE ID	Surface	Road Type	Avg Lum	Avg Ill	Avg Lum	Avg Ill	Avg Lum	Avg Ill	Avg Lum	Avg Ill
A,F	IES Standard		0.80	1.20	0.80	1.20	0.80	1.20	0.80	1.20
B,C	IES Standard		0.50	0.70	0.50	0.70	0.50	0.70	0.50	0.70
250 A	R3	Collector	2.62	3.03	2.19	2.64	1.81	2.18	1.46	1.76
			328%	253%	274%	220%	226%	182%	183%	147%
250 B	R1	Local	1.43	1.21	1.39	1.04	1.15	1.04	0.93	0.84
			286%	173%	278%	149%	230%	149%	186%	120%
250 C	R1	Local	1.66	1.44	1.52	1.39	1.26	1.15	1.02	0.93
			332%	206%	304%	199%	252%	164%	204%	133%
250 F	R2	Collector	2.59	3.12	2.13	2.60	2.13	2.15	1.42	1.74
			324%	260%	266%	217%	266%	179%	178%	145%
Total	*Average*		*317%*	*223%*	*281%*	*196%*	*244%*	*168%*	*188%*	*136%*
A,F	*Average*		*326%*	*256%*	*270%*	*218%*	*246%*	*180%*	*180%*	*146%*
B,C	*Average*		*309%*	*189%*	*291%*	*174%*	*241%*	*156%*	*195%*	*126%*

Data source: Witness Bellini's Work Paper J - Application Performance Results 250 HPS All LED to HPS 11 11 22. Note: revision corrects Road Type for 250 A from "Unspecified" to "Collector".

Q. Could DTE satisfy lighting standards by using lower-wattage LEDs on the modeled roadways, instead of the 58w and 136w models used now?

A. Yes, the data provided by Mr. McLean strongly suggest it could in almost all cases. The "100A-100G" roadways he modeled would provide, on average, 143% of the luminance standard with 37w LEDs, with only one of the seven roadways coming in below the standard.

The modeling results make an even more compelling case for using a lower-wattage LED over the "250A-250D" roadways. If the Company were to step down to a 72w LED instead of 136w LED in place of 250w HPS fixtures, average roadway luminance would still be 188% of the standard level.

Q. If the models show that lower-wattage LEDs would comply with roadway lighting standards, then why did the Company's experts rule out their use?

A. The Company's experts ruled out the use of lower-wattage LEDs because they were not

asked to find which LEDs would best satisfy roadway lighting standards. Rather, they were asked to determine which LEDs would best match incumbent HPS lights.

Q. What would be the benefit of using lower-wattage LEDs?

A. The 37w luminaire uses about 36% less electricity than the 58w model. The cost of service of a 37-watt LED is about $34 less per year than that of a 58w LED ($203 vs $237).[57] The 72w LED luminaire uses just over half the electricity of the Company's preferred 136w LED. Witness Bellini's Lighting Rate Model shows that the 72w LED has a COS total rate of $271.50 per year, whereas the Company's preferred 136w model has a COS total rate of $374 – more than $100 extra per year.

Q. Modeling aside, do any other streetlight service providers in Michigan use HID-LED conversion practices similar to what you recommend?

A. Consumers Energy and the City of Grand Rapids both use significantly lower LED wattages to replace common HID wattages than DTE does.

Consumers Energy, for example, uses a 40-watt LED cobrahead luminaire as the standard replacement for 100-watt high pressure sodium (HPS) luminaires.[58] For this same conversion, DTE uses a 58-watt LED luminaire, which uses 45% more electricity than Consumers' choice. It costs DTE about $15 more to buy a 58-watt LED than a 40-watt LED.[59] The cost of service for a 58-watt LED cobrahead luminaire is about $17 more per year than for a 40-watt LED. Across the board, Consumers is replacing HID luminaires with LED luminaires that are cheaper and use less electricity than DTE's choices. The

[57] WP RAB U-21534 Lighting Rate Model, Output worksheet, Column AP.
[58] Exhibit MAU-32, Consumers Energy LED Streetlight Crossovers, excerpt from testimony of Consumers Energy witness Schmoekel in case no. U-21585.
[59] WP RAB U-21534 Lighting Rate Model, E1 Option I OH, worksheet.

choice is consequential for customer cost, lighting quality and customer climate and energy goals.

Differences between Consumers' more-rural service territory compared to DTE's may justify differences in standard lighting levels. However, DTE also serves rural areas and has not shown that it uses different lights there than in cities. Furthermore, this point simply underscores why it is important to choose lights based on standards that take such factors into account, rather than using a cookie-cutter approach.

Given this observation, it may nevertheless be useful for the Commission also to consider how another large street lighting provider has converted to LEDs in an urban environment. The City of Grand Rapids recently completed conversion of its streetlights to LED. Grand Rapids uses 55-watt LEDs to replace 100-watt HPS luminaires – closer to DTE's choice of 58-watt LEDs. However, Grand Rapids also installs dimmers on its LEDs, and drives those 55-watt LEDs initially at 70% of maximum, equivalent to only about 40 watts.[60] As the luminaire's light output slowly decreases over time, Grand Rapids can adjust to yield constant illumination by giving the luminaire more electricity. This practice also significantly extends the service life of the luminaire, which saves the City money, because replacing failed lights is more expensive.

Q. What conclusion do you draw from the fact that other streetlight conversions in Michigan use lower wattage lights or operate similar lights at lower wattage output?

A. The Commission was right to deny recovery to DTE for the unreasonable costs its unusual LED conversion choices cause customers in U-21297, and it should do so again in this

[60] Exhibit MAU-33, Grand Rapids LED Conversion, "City of Grand Rapids FOIA Response Letter to Request PR-2024-368 to Michigan Municipal Association for Utility Issues," answers 1 and 6.

case. DTE has failed to offer evidence that the Commission should reconsider the unreasonable nature of the costs that DTE's choices are creating.

DTE's LED conversion practices, according to its own modeling, result in overlighting of public streets. Other large streetlight fleet owners in Michigan use different practices, suggesting that DTE has viable options for improving its compliance.

Q. Witness Bellini recommends that the Commission should reverse itself by allowing the Company to recover on the $5.8 million in excess LED costs disallowed in case no, U-21297. Do you agree?

A. No. The evidence in this case clearly shows the Company has cost-effective ways to improve compliance with ANSI/IES RP-8 that it has not properly evaluated, and it is not making lighting that is more likely to comply with lighting standards available without charging an up-front CIAC and imposing other cost and staffing burdens on customers who wish lights that better meet their lighting, environmental, and economic goals.

Q. Witness Bellini recommends that the Commission order a technical collaborative on lighting conversion standards if it is not prepared to approve the Company's LED costs with its order in this case. Do you agree?

A. No, I do not agree. DTE's own technical experts have given it all the information it needs to understand that its conversion practices usually overlight roadways. Until recently, its own preferred supplier had a conversion chart that suggested DTE's selections were more expensive than were recommended. Other utilities in Michigan choose lights of lower wattages or deliberately operate them to consume less energy and last longer. If DTE will not accept that it is wrong when it is out of step with its peers, its supplier, and even the analysis of its own experts, a technical conference is unlikely to do more than absorb a lot

of time without achieving any consensus.

If DTE can present comprehensive and credible technical and cost information in a rate case filing about why its preferred light is more likely to comply with roadway lighting standards than the more usual alternatives, which intervenors can then scrutinize and reply to, then a technical collaborative may be a reasonable path forward. Ordering one in this case, in which the Company's experts provide some of the best evidence that the Company's lights are too expensive, would not be appropriate.

Q. Has DTE continued to install the same LEDs that the Commission found were unreasonably expensive in its order in case no. U-21297?

A. Yes, it has. The Commission should not allow the Company to recover on unreasonable LED costs it has incurred subsequent to the order in case no. U-21297. The Commission found that the Company's LED costs were unreasonable, yet the Company persists in the very overspending the Commission disallowed. Below, I explain how the Commission should update this disallowance, and provide a supporting exhibit.

Q. Why should the Commission update the LED luminaire plant in service values that it disallowed in case no. U-21297?

A. The disallowance in plant-in-service values should be updated to include unreasonable costs incurred after the plant balances used to calculate the disallowance were established. The Company has continued to install the unreasonably costly LEDs, thus increasing the unreasonable costs. It should no more be allowed to recover those new excessive costs than it was the historic excessive costs.

Q. How do you propose calculating the updated disallowance amount?

A. There are two reasonable approaches; one is to follow the same procedure as last time,

including substitutions of the same LEDs. This is a reasonable approach because Leotek has not disavowed the chart that the Commission used in U-21297, so there is no indication that continuing the same method previously used is currently unreasonable.

The second approach is to benchmark against another regulated provider in Michigan. The obvious choice in this regard is Consumers Energy, and use the lights Consumers Energy installs as the comparison set.

I recommend that the disallowance should be baselined against the recommendations available from Leotek in the last rate case, because Leotek is DTE's supplier and this will allow consistent YOY calculation methods. That said, using the Consumers Energy data as an alternative guide for a more reasonable conversion model for each type of light would also be reasonable.

Q. What disallowance amount do you recommend?

A. I recommend that the Commission disallow $7,705,567 in unreasonable LED conversion costs to date, based on the most recently available equivalency recommendations made by DTE's supplier, Leotek. If the Commission prefers to use Consumers Energy's LED equivalencies as a benchmark, then the disallowed amount should be $5,833,539.[61]

Q. Is your recommended disallowance cumulative or incremental to the amount disallowed by the Commission in case no. U-21297?

A. My recommended disallowance is cumulative; that is, it covers costs of LEDs installed both before and after the Commission's order in case no. U-21297.

The reason I am providing a cumulative figure is that I have improved my calculation of the disallowance. In case no. U-21297, I used the difference in tariffs for DTE's LED

[61] Exhibit MAU-34, LED luminaire plant balance disallowance.

choices versus those recommended by the manufacturer. In my instant recommendation, I am using the difference in cost of service. Using differences in rates between different LED models, as I did before, is imprecise because those very rates change depending on the case outcome. In addition, because the Company is still adjusting streetlight rates slowly to align with cost of service, many rates still differ significantly from cost of service.

Q. Is your proposed disallowance a conservative estimate of unreasonable costs resulting from DTE's imprudent conversion practices?

A. Yes. My proposed disallowance is conservative, in two ways.

First, my proposed disallowance excludes costs of a significant number of LEDs that the Company has installed. I excluded LEDs of wattages that are deployed in small numbers because I do not have reliable data on what wattage of HID lamps they replaced; consequently, I do not know what replacement LED Leotek would have recommended.

Second, my proposed disallowance assumes that all the LEDs included in my analysis were installed in place of HPS fixtures. But we know that many were installed in place of MV fixtures, and we know that Leotek recommends substantially larger reductions in wattage for MV-LED conversions. The data on MVs that have been replaced by LEDs is older and less reliable than that for HPS conversions, and rather than estimating I made the simplifying assumption that all decommissioned HID fixtures to date have been HPS.

Given these two conservative elements of my approach to the analysis, my proposed disallowance should be understood to represent a significantly smaller amount than DTE's actual level of overspend on LED conversions.

Q. Do you have any other concerns about DTE's continued use of LED luminaires that the Commission has found to be too expensive?

A. Yes, I do. Excessively bright street lighting is not only a utility-cost concern: it creates several external costs. Excessive outdoor lighting has social, human health, environmental and scientific impacts. Attainment of state and local climate change goals are impeded by lights that use too much energy. Lights of the preferred color temperature improve visibility in ways that promote traffic and pedestrian safety. Light trespass risk also increases when lights are brighter than needed, and fewer city-dwellers can see the stars. These impacts, which go beyond the financial, point to why regulatory oversight of this matter is so important.

Community Lighting Rate Design

Q. What rate design topics will you address here?

A. I will address the Company's continuing gradual adjustment to streetlight rates to bring them into alignment with the cost of service.

Q. Do you support continued gradual adjustment of E1 streetlight rates to bring them into alignment with cost of service?

A. No, I do not. I recommend the Commission order adoption of full cost of service rates in this case. The gradual adjustment has not worked as intended nor within a reasonable timeline, and its perpetuation causes a subsidy of less-efficient lights by more-efficient LEDs.

Q. Why did the Commission order the gradual adjustment?

A. As of 2016, streetlights served by underground wires ("UG") were paying more than the cost of service, and streetlights served by overhead wires ("OH") were paying less than the cost of service. A one-time adjustment would have caused a rate shock for customers with a preponderance of OH lights, many of whom are older communities with limited financial

ability to absorb rate increases.

The less disruptive way out of this problem was to adjust the rates slowly, which would also give those customers time to transition their existing OH lights to LEDs. Because LED rates are lower than HID rates, the change in technology could fully (or more than) offset the concurrent change in relative OH and UG rates.

Q. Why do you believe the period of gradual rate adjustment should end?

A. Customers have had plenty of time, by now, to convert to LED to offset increases in OH rates. The Commission commenced this process with its order in Case no. U-18014 on January 31, 2017. Since then, more than seven years have elapsed, and the Company has filed six subsequent rate cases. The Company and the state have offered consistent and significant technical and financial support to customers to convert their OH lights to LED. Seven years is a long time to pay less than the costs you are causing, and customers who have spent time and effort to lower their bills through LED adoption should not continue to subsidize communities that have put their resources elsewhere. Subsidized OH rates are causing rates for customers with UG lights, customers with LED lights and customers served under rates E1, Options II and III to pay higher than their cost of service, which is not fair.

Furthermore, continuing the subsidy of OH lights results in all LED lights paying more than their cost of service, a perverse disincentive to reduce energy waste which the Commission should seek to avoid. The Company's proposed rates would have LED lights (OH and UG combined) paying about $1 million more than cost of service.[62]

[62] Exhibit MAU-34, WP RAB U-21534 Lighting Rate Model, Output sheet, MAUI-modified (LED totals for columns 195 +196).

Q. Aside from the perverse or unfair subsidies created by the slow adjustment to cost of service, is the gradual adjustment serving its stated objectives?

A. No, it is not. Witness Bellini's Lighting Rate Model shows that, collectively, UG lights are currently annually paying $156,935 more than cost of service.[63] Witness Bellini's proposed revenue for UG lights under the E1 rate would be $745,523 higher than Cost of Service.[64] Rather than being a gradual move towards cost-causation, the proposed rates would move drastically in the opposite direction. Stated another way, the Company's proposed rates for UG lights would widen the gap between the cost of service compared to current rates. Thus, the mechanism is failing not only to accomplish its intended objectives of moving gradually to cost of service, but while doing so, is also failing to signal to customers the true cost advantages of moving to LEDs.

Q. What is your recommendation to the Commission regarding E1 rate design?

A. Tariffs for all E1, Option I lights should reflect full cost of service and the adjustments should be concluded.

Summary of Municipal Street Lighting Recommendations

Q. Please summarize your street lighting recommendations to the Commission.

A. In the same order as above:

- The Commission should eliminate the CIAC for HID-LED conversions from the tariff, whether individual or group conversions. The only exception should allow CIAC for special order materials that are not more likely to comply with

[63] Exhibit MAU-34, WP RAB U-21534 Lighting Rate Model, Output sheet, MAUI-modified (total of column 79).
[64] Exhibit MAU-34, WP RAB U-21534 Lighting Rate Model, Output sheet, MAUI-modified (total of column 196).

streetlighting standards. Relatedly, the Company should stop servicing HPS fixtures right away, with the only exception being for customers who want to keep HPS fixtures in service as long as possible.

- I recommend that the Commission instruct DTE to file a bill credit method and initial amount with its next rate case, including the features I have described above, to assure equitable rate treatment of customers who have paid for past LED conversions versus those who will receive them with no CIAC in the future. I also recommend that the Commission instruct DTE to consult with staff and intervenors in the development of its proposed credit scheme in advance of its next filing.
- For the street lighting sales forecast, I recommend a reduction of 3,308,045 kwh, equivalent to 4.06% of DTE's unadjusted forecast for E1, Option 1 streetlights, to adjust for known outage rates when streetlights are using no, or almost no, energy.
- I recommend that the Commission approve the Company's proposal for streetlight outage reporting to customers, including witness Bellini's proposal to narrow the scope of reporting to E1, Option I lights only. However, I recommend the Commission include two additional stipulations in its order. First, the Commission should set a deadline by which the Company will provide customers with the outage reports. I recommend that Commission order the Company to provide initial quarterly outage reports to large customers for Q3 and Q4 of 2024 by January 31, 2025; and thereafter comply with the reporting schedule detailed by the Commission in its order in case no. U-21297. Second, in the next rate case filing, the Company should be required to make a specific proposal and timeline for

including accurate outage counts by light, rather than bundling multiple lights into reported outage events.

- I recommend that the Company be instructed to include in its next rate-case filing information regarding its inspection and painting annual targets as well as a report on inspection and painting completed in the prior years and the costs incurred for such activities;
- I recommend that the Commission order DTE to include street lighting capital and distribution O&M plans in its Distribution Grid Plan, including reliability, energy efficiency and cost-benefit analyses.
- Regarding O&M costs, I recommend the Commission approve $941,950 for Community Lighting Supervisory and Administrative staff (instead of the proposed $1,800,000) and allow no cost recovery for streetlight inspections and painting in the projected test year.
- I recommend the Commission approve other proposed O&M line items specified in this testimony (e.g. the costs of the new outage management system).
- I recommend the Commission require the Company to provide outage event root-cause data in the next rate case filing, covering both customer-reported outages and Night Patrol outages, to facilitate informed analysis of the Company's outage response and prevention expenditure proposals. Rather than being more prescriptive than this in its order, I would recommend the Commission order the Company to propose a sample report within three months of its final order in this case, for review and discussion with MPSC Staff and intervenors.

- Regarding streetlight capital costs, I recommend the Commission disallow spending on the underground cable replacement program. This program was not discussed in the Company's DGP and no meaningful cost-benefit analysis is included with the Company's filings in the instant case.
- I recommend no changes to other capital expense line items. Therefore I recommend that total test-year capital expenditure for Community Lighting should be $15.575 million.
- I recommend that the Commission maintain its disallowance of unreasonable spending on excessively bright LED streetlights as ordered in case no. U-21297, and to disallow excessive spending on LEDs installed since then. The total cumulative disallowed amount should be $7,705,567.
- I recommend that the Commission order the Company to implement full cost-of-service rates for all E1 rate schedules.

IV. MUNICIPAL COORDINATION PRACTICES

Q. Why do local governments want better coordination of electric infrastructure projects with DTE?

A. Local governments can be impacted by uncoordinated infrastructure project coordination in several ways. Poor coordination of projects can lead to:

- avoidable damage to municipal infrastructure or easements.
- avoidable levels of disruptions to residential neighborhoods, business districts and vehicle traffic.

- avoidable costs that impact the electric rates paid by the residents and businesses served by local governments.

Q. Can you illustrate how a utility project might cause avoidable problems and costs?

A. Utilities often need to excavate, or otherwise operate, in the public right-of-way or easements. Such projects may be coordinated with municipal (or other) infrastructure projects that could be implemented concurrently or consecutively. While coordination of project implementation may cause costs of its own, as might adjustment of utility-project timelines, financial economies may also be realized related to permitting processes, excavation, and infrastructure repair costs. Municipal governments, for example, plan road, sidewalk, water and sewer projects typically years in advance; excavations conducted during these projects may create the opportunity for a utility to service or install its own underground infrastructure. If the utility were to implement its own project before or after the municipal project, avoidable damage and disruption might be incurred.

The need, and opportunity, for this kind of coordination is growing as project volumes grow. Increased federal infrastructure spending, along with emphasis in Michigan on improving road conditions, is causing local governments to increase the scope and scale of their infrastructure projects. At the same time, DTE is significantly increasing investments in its electric infrastructure to improve reliability and resilience, support distributed resources and electrification of buildings and vehicles. Many local governments are keenly interested in the undergrounding of electric infrastructure as a reliability measure, the high costs of which might be reduced were projects scheduled to coincide with local road, water, sewer and other projects. The opportunity to coordinate project planning and scheduling has never been greater, nor has the need to seek financial economies to moderate the impact

of all these projects on electric rates, taxes, and quality of life in communities served by these projects.

This recent and future coincidence of escalating investment in utility and municipal infrastructure heightens the need for coordination to reduce disruptions to the community. It is said that Michigan experiences five seasons: winter, spring, summer, fall and construction – highlighting the inconveniences forced on residents and businesses by the short seasonal window of opportunity afforded to infrastructure projects in Michigan. Exacerbating this unavoidable consequence of our climate by missing opportunities to coordinate projects adds insult to injury.

City of Ann Arbor witness Stewart provides examples of actual infrastructure project coordination opportunities that DTE's normal processes failed to identify.

Q. Has the Commission addressed infrastructure project coordination in prior DTE case orders?

A. Yes. In its final order in case no. U-21297, the Commission wrote:

> "…in its next rate case, DTE Electric shall include a demonstration of its efforts to improve communication and coordination with local governments regarding construction activities."[65]

Q. Did the Company respond fully to this order in its filing in the current case?

A. No, it did not. Witness Kryscynski testified:

> "When DTE is ready to move forward with a capital project the Company coordinates with the appropriate municipal personnel to set up a briefing meeting to discuss the details of the project, benefits, and collaboration opportunities of the work. We request that the municipality provide any potential conflicts to the project before permits are sought. This provides both the municipality and DTE some assurance that the planned project

[65] U-21297 final order, p361.

> does not conflict with a municipal project, whether it's in the conceptual or planned stage.
>
> Once the project is in progress, periodic updates are provided to the municipality and meetings may be held work through any questions that arise. …
>
> The company is working to improve the frequency of updates to municipalities and garnering feedback to determine their preferred methods to receiving these updates. In addition, we are working with county road commission to support their projects, and to coordinate where possible to avoid conflicts."[66]

Q. How does witness Kryscynski's testimony fall short of fully responding to the Commission's prior order?

A. Witness Kryscynski's testimony falls short in multiple ways.

First, where the Commission ordered the Company to provide a "demonstration of its efforts," witness Kryscynski provides only a cursory, high-level description of how the Company approaches a complex and complicated process. A demonstration would involve data, a more detailed description of policies and practices, and examples.

Second, the Commission said it wanted a description of the Company's efforts to *improve* coordination. Witness Kryscynski's testimony does not do that. The Company describes communications that occur after the Company has decided when and where it will be working – communications that are very similar to what the Company did in previous years. If this is in any way an improvement, it is still a description of communication, not coordination. This belated communication robs both DTE and the local government of opportunities to compare planned projects over the next 5-6 years and choose to schedule co-located projects concurrently or consecutively. Thoroughgoing coordination would

[66] Kryscynski direct testimony, AJK-102, lines 6-22.

involve consultation from the beginning of the prioritization and planning processes, not a separate process that culminates in belated notification.

Third, witness Kryscynski twice refers to conflict avoidance, as if that is the only value DTE sees in coordination and communication. While that is valuable, concurrent or consecutive scheduling may yield the best results for minimizing costs and disruptions for both parties. Ann Arbor witness Stewart lists several costs – totaling a notable percentage of overall costs for a project, which DTE can avoid by coordinating a single project. For instance, without coordination, DTE may have to bear the costs of sidewalk restoration; with coordination those costs could be avoided. Municipal governments, in contrast to DTE, see coordinated project planning and implementation as an opportunity as well as a risk-management exercise, and as part of their responsibility to the ratepayers and taxpayers they serve.

Q. Did you ask the Company to elaborate on witness Kryscynski's testimony in discovery?

A. Yes. In discovery request MAUIDE-2.8, MAUI asked DTE to "list all projects in the historical test year, or which are planned from now through the end of the test year, that were or are planned to be coordinated with another utility or local unit of government." DTE's response included the following statements: "The Company does not currently have a database system that includes coordination efforts between the Company and other utilities or local units of government," and, "there is no formal analysis on this work." DTE's response went on to provide "some examples that are illustrative of the coordination between DTE, local units of government and other utilities. Included in these examples are DTE-owned or municipal-owned projects on which DTE *collaborates to resolve conflicts*

and eliminate delays where possible." [67] (emphasis added)

In addition, Ann Arbor asked specifically "how the Company has complied with the Commission's directive in Case No. U-21297 to 'include a demonstration of its efforts to improve communication and coordination with local governments regarding construction activities.'" In response DTE referred solely to MAUIDE-2.8.[68]

Q. How did DTE's discovery response demonstrate lack of understanding of the purpose of the Commission's directive in case no. U-21297?

A. The Commission's prior order sought to encourage the Company to proactively plan projects with local governments. The list of projects witness Kryscynski provides in his discovery response fall into two categories: municipal projects for which the local government has requested relocations of DTE infrastructure, and DTE projects that depend on local government permitting or other enabling actions. These are mostly examples of tactical and final-stage coordination: DTE responds when asked, and in turn asks for local help to facilitate its own projects. DTE provides no evidence that it is aware of or incorporating local infrastructure project plans so it can plan and schedule its own projects in ways that might realize cost efficiencies or reduce disruptions.

Q. Are there any other indications that DTE has not tried to improve its communication and coordination with local governments?

A. Yes, there are such indications. An examination of DTE's FERC accounts for Regional Relations (which it describes as work with local governments to "facilitate dialogue on operational matters such as storm recovery, infrastructure improvements and other capital

[67] Exhibit MAU-39, response to MAUIDE-2.8.
[68] Exhibit MAU-38, response to AADE-1.7.

projects") suggests the Company is not committed to improving its communication or coordination with local governments. The total of these FERC accounts in the historical test year (2022) was $0.733 million, and the total requested for the projected test year (2025) is $0.801 million, which is the "adjusted historical cost of $733,000 plus inflation."[69]. Thus, DTE is demonstrating its intent to maintain the status quo regarding its relations with local governments and not to devote any additional staff time to coordination efforts.

Q. Do local governments employ processes for planning and coordinating infrastructure projects and communicating plans and priorities to stakeholders?

A. Yes. Local governments are required to produce Capital Improvement Plans (CIPs). In implementation of their CIPs, local government agencies also conduct careful coordination of municipal infrastructure projects with each other and with private infrastructure projects. These processes are neither easy nor fast, but they represent the responsibility of local governments to manage costs and disruptions caused by projects. Participation in such processes would not cause delays or interfere with any franchise rights, but rather allow DTE to coordinate with municipalities and other utilities in a way that would minimize conflicts but also identify cost-saving opportunities.

Q. Please describe CIP objectives and content.

A. CIPs are roadmaps for local governments' long-term investments in their physical assets. These plans aim to achieve several key objectives including strategic alignment, efficient resource allocation, financial planning, project prioritization, and proactive infrastructure management. A typical CIP centers upon a multi-year list of capital-intensive projects, such

[69] Exhibit MAU-41, response to MAUIDE-1.2.

as new construction, renovations, and equipment purchases for physical assets like roadways, sewer lines, public buildings, and more. Accompanying the project list are annual forecasted expenditures, funding sources, location, and timeline for each project.

Q. How are CIPS developed?

A. Every municipality has their own distinct process for developing a CIP. In general, though, the development process is highly collaborative and includes the following pieces:

- Initiation and Leadership: the CIP project is kicked off and a lead department is designated.
- Needs Assessment: municipal infrastructure needs are identified through department project proposals.
- Project Evaluation and Prioritization: submitted projects are evaluated on a variety of factors, potentially including urgency, alignment with strategic goals, environmental impact, and potential community benefits.
- Financial Analysis: project costs are estimated, and potential funding sources are explored.
- Drafting and Public Input: a draft CIP is prepared and presented to relevant stakeholders for feedback and adjustments.
- Review and Approval: relevant governing bodies review and approve the CIP.
- Updating and Monitoring: the approved CIP is updated periodically to reflect changes in priorities, funding, and project progress.

Q. How are CIPS communicated?

A. Similar to the previous answer, each local government communicates their approved CIP in different ways. CIPs are typically documented as either a spreadsheet or pdf document

and uploaded to municipal websites.

Q. Would a CIP normally contain information that could constructively inform utility infrastructure project prioritization and planning?

A. Yes, it would. CIPs contain information on planned and in-progress municipal infrastructure investments. Relevant project information includes the timeline, location, and type of project (i.e., surface penetration). Knowing such information would answer the "when", "where", and "what" of project planning, and could help inform a utility about potential project coordination opportunities.

Q. Are CIPs readily available for utilities to review?

A. Yes. They are public records. In most cases, local governments make them readily available through their websites. If a CIP were not available on a website, a utility could easily get a copy by contacting the local government – no FOIA request is needed.

Q. Are the CIPs of MI-MAUI member governments readily available to anybody?

A. Yes, they are. MI-MAUI was able easily to locate and download member governments' CIPs online using simple web search methods.[70]

Q. Does DTE review local government CIPs when planning and prioritizing its own electric infrastructure projects?

A. No, it does not.[71] Witness Kryscynski offers, in elaboration, that "Once a DTE project is selected to move forward, our local governmental affairs team reaches out to the affected municipalities to notify them of the work and identify potential coordination opportunities." Ann Arbor witness Stewart's testimony provides a concrete example (no

[70] Exhibit MAU-36, Capital Improvement Plans Google search results
[71] U-21534 Exhibit MAU-37, response to MAUIDE-2.5.

pun intended) of opportunities this approach can easily miss, and the increased costs that result from failing to take advantage of those opportunities.

Q. Does DTE coordinate project planning with local governments in other ways?

A. Yes, it does, but DTE normally initiates this coordination late in the planning process, potentially avoiding outright conflicts but missing opportunities to save money and reduce disruption through joint project implementation. For example, DTE provides an extensive list of projects in Detroit that require relocations or coordination.[72] These efforts are appreciated and important, but reflect the Company being responsive to customer requests rather than proactive about coordinating and communicating its own plans and work and finding opportunities to identify cost savings.

Q. Does DTE Electric coordinate with other right-of-way users?

A. DTE Electric does not routinely coordinate, even with DTE Gas on infrastructure projects. Witness Deol states, "The Buffalo-Charles pilot project was the first construction collaboration between DTE Electric and DTE Gas. Based on the efficiencies realized the company will determine next steps."[73] It is notable that collaboration even between "sister" companies of DTE has never been attempted before, and witness Deol's response suggests this first-of-its-kind project will be used to definitively determine whether future collaborations occur.

Recommendations Regarding Coordination

Q. Please summarize your recommendations to the Commission regarding coordination of DTE electric infrastructure projects with local governments.

[72] U-21534 Exhibit MAU-39, response to MAUIDE-2.8
[73] U-21534 Exhibit MAUI-40, response to MAUIDE-2.7.

A. The Commission should make clear that it will presume that 10% of the costs of electric infrastructure projects that involve excavation in the public right of way or easements are not recoverable unless the Company can show neither DTE Gas nor the government plans potential work in the same area, or that the Company made reasonable attempts to coordinate work with such projects. In most cases, the requirement regarding local governments could be met by reference to publicly-available CIPs with very little effort. For example, the Commission should require DTE to demonstrate that it prioritizes locations of infrastructure undergrounding and underground maintenance projects, in part, by identifying local-government infrastructure projects that require excavation with which the DTE projects could be co-located and -scheduled. This discipline should apply to preventive maintenance projects, as well: the Company should prioritize maintenance of its underground infrastructure at times and places where local governments plan to implement their own infrastructure projects.

Given DTE's lackluster response to the Commission's order in the last rate case, it is important that the Commission set a higher and clearer bar for this requirement than it did with its order in case no. U-21297. The Company's filings and responses in the instant case on this issue gave cursory attention to the Commission's prior order. The Commission should be more prescriptive in its order in this case.

Q. Does this complete your direct testimony?

A. Yes, it does.

Q. Do you swear under penalty of perjury that the statements above are true to the best of your knowledge, information and belief?

A. Yes.



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3 Richard Bunch

MS. BRADER: Next, per stipulation, I move to bind into the record six additional exhibits, which are also sponsored by Mr. Bunch, which consists of 120 pages in total, designated sequentially as MAU-42 through MAU-47, and which are available on the SharePoint for this hearing. These exhibits are as follows: MAU-42 is a Detroit Crime Data Compilation, MAU-43 is DTE's Discovery Response MAUIDE-3.87 from U-20836; MAUI-44 is page 31 of Mr. Bellini's direct testimony in Case No. U-20836; MAU-45 is DTE's Discovery Response MAUIDE-9.4a from Case U-21297; MAUI-46 are pages 16 and 17 of Mr. Bellini's Direct Testimony in Case No. U-21297; and MAUI-47 is an NCHRP Study.

JUDGE WALLACE: Thank you, Ms. Brader. Is there any objection to binding in -- not binding in -- admitting Exhibits MAU-42 through MAU-47?

Hearing none, those exhibits are admitted.

MS. BRADER: That concludes all the motions for both, for MI-MAUI as well as the City of Ann Arbor, your Honor. Thank you.

JUDGE WALLACE: O.K. Thank you very much. Next, Mr. Templeton.

MR. TEMPLETON: I guess it is good afternoon at this point, your Honor. So on behalf of

Soulardarity and We Want Green, Too, known collectively as the Detroit Area Advocacy Organizations, I'm going to move to bind in the testimony and rebuttal testimony, the direct testimony of seven witnesses, rebuttal testimony of one of those witnesses, and then move for admission of a number of exhibits.

So first, on behalf of Detroit Area Advocacy Organizations, I move to bind in the Direct Testimony of Jackson Koeppel, which consists of a cover page and 65 pages of questions and answers. In that direct testimony, he sponsored Exhibits DAO, D-A-O, Exhibits 1 through 28, inclusive. Mr. Koeppel -- can we just stop there, or do you with want me to do the rebuttal also at this point, your Honor?

JUDGE WALLACE: Go ahead and take care of rebuttal as well.

MR. TEMPLETON: O.K. On behalf of the Detroit Area Advocacy Organizations, Mr. Koeppel also filed written rebuttal testimony, consisting of a cover page and 11 pages of questions and answers, and in that, he sponsored Exhibit DAO-29. So I move to bind in Mr. Koeppel's direct and rebuttal testimony, and move for the admission of Exhibits DAO-1 through 29, inclusive.

JUDGE WALLACE: Thank you, Mr. Templeton. Is there any objection to binding in the direct and

rebuttal testimony of Mr. Koeppel?

Hearing none, the testimony is bound in.

Is there any objection to the admission of Exhibits DAO-1 through DAO-29?

Hearing none, those exhibits are admitted.

(Testimony bound in.)

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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 ALJ Sally L. Wallace

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DIRECT TESTIMONY OF JACKSON KOEPPEL

ON BEHALF OF

DETROIT AREA ADVOCACY ORGANIZATIONS

(SOULARDARITY AND WE WANT GREEN, TOO)

July 26, 2024

I. INTRODUCTION AND SUMMARY

Q: Please state your name, occupation, and business address.

A: My name is Jackson Koeppel. I am an independent consultant, primarily focused on working on energy regulatory issues for Soulardarity and We Want Green, Too. My business address is 189 Monterey St, Highland Park, MI 48203.

Q: On whose behalf are you submitting this direct testimony?

A: I am testifying on behalf of Soulardarity and We Want Green, Too collectively the Detroit Area Advocacy Organizations (DAAO).

Q: Please describe your work experience.

A: I moved to Highland Park, Michigan in 2012 and co-founded Soulardarity, an organization rooted in the Highland Park community, to organize for community-owned solar streetlights and energy democracy. I served as the organization's primary staff and founding Executive Director. Shimekia Nichols succeeded me as Executive Director of Soulardarity in 2021. I have contributed to work locally, regionally, and nationally to democratize and decarbonize our energy economy as an independent consultant. My work has included developing original research, regulatory interventions, coordination of state and regional networks, and development of implementation programs for energy transition.

Q: For what purpose was Soulardarity created?

A: In 2011, DTE Energy repossessed more than 1,000 streetlights from Highland Park, Michigan, a predominantly low-income and people-of-color city, after its municipal government defaulted on its electric utility payments. A coalition of Highland Park residents formed Soulardarity in 2012 to help alleviate this crisis by installing community-owned, solar-powered streetlights in the city. Soulardarity's mission has subsequently broadened to include energy education and advocacy for community solar and greater equity in Michigan's energy generation and delivery systems. Through activism and advocacy, Soulardarity emphasizes the particular needs, experiences, and perspectives of low-income communities and communities of color.

Q: What is Soulardarity's focus?

A: Soulardarity's focus is improving access to affordable, clean energy for low-income communities and communities of color, including women, children, the elderly, people with disabilities, and others who live in poverty. As such, Soulardarity promotes solar street lighting, solar bulk purchasing, energy education, job training, and expanding access to clean energy. These efforts aim to improve the economic condition of low-income communities, especially low-income communities of color, in southeast Michigan. Soulardarity has developed partnerships with other Michigan stakeholders interested in energy justice and affordability, including experienced solar installers, solar developers, environmental justice advocates, and public health experts. Soulardarity also advocates for equitable utility rates and services, including but not limited to investments in reliability, safety, and energy waste reduction, on behalf of low-income communities

and communities of color. Finally, Soulardarity pushes for reducing the burdens of fossil-fuel energy generation on low-income communities and communities of color and for just transitions from the fossil-fuel energy economy to the clean energy economy.

Q: For what purpose was We Want Green, Too created?

A: We Want Green, Too was created to develop programs to assist veterans with post-traumatic stress disorder in in transforming their lives and communities as sustainability leaders.

Q: What is We Want Green, Too's focus?

A: Early on, We Want Green, Too focused on giving veterans opportunities to work with their hands on building projects. This effort began with an experimental, energy efficient renovation for a home in Jackson, Michigan with four veterans. It continued with the rebuilding of a blighted 2200 square foot home on Detroit's east side, incorporating energy-efficient retrofits. These projects illustrate how to build homes that reduce utility costs and increase health by creating spaces with healthy, clean indoor air. We Want Green, Too's current projects include deconstructing three blighted buildings to create a multi-family energy efficient housing unit, as well as launching solar and energy efficiency job-training programs. Other programming includes get-out-the-vote outreach, youth mentorship, crisis response, and direct employment and mental-health support for veterans. We Want Green, Too has also formed collaborative partnerships with local organizations such as The Villages Community Development Corporation, churches, and other nonprofits to continue to understand community needs. We Want Green, Too is

also a member and partner of Michigan Environmental Justice Coalition (MEJC), which engages in on-the-ground work to that promote energy justice and energy efficient housing and fights against disinvestment, unemployment, and threats to community health in Detroit's East Side.

Q: Have Soulardarity and We Want Green Too previously intervened in or commented on an MPSC matter?

A: Yes, Soulardarity intervened in DTE's 2018 rate case, MPSC matter U-20162, and DTE's 2019 rate case, MPSC matter U-20561, and DTE's 2022 rate case, MPSC matter U-20836. In these rate cases, Soulardarity advocated, through testimony and briefing, for a more equitable rate design through the provision of increased resources in underserved communities and for policies that promote access to distributed generation programs for low-income and people-of-color ratepayers. Beyond the rate cases, Soulardarity intervened in MPSC matter U-18232 and advocated, through testimony and briefing, for the inclusion of community solar projects in DTE's Renewable Energy Plan (REP) and for the accommodation of low-income, people-of-color ratepayers in DTE's energy decision-making. Soulardarity filed a comment in MPSC matter U-18418 regarding the proposed Integrated Resource Planning (IRP) process and advocated that the process include more robust engagement with stakeholders from low-income, people-of-color communities. Soulardarity also commented during the MPSC Staff's development of the Distributed Generation Tariff in MPSC matter U-18383 and advocated for changes that would increase transparency and access to solar energy for low-income communities and communities of color. Soulardarity joined a Response to Prior Comments in MPSC matter U-18076

concerning DTE's application for Commission approval of a previous amended REP. Soulardarity has also intervened and raised similar concerns in DTE's 2019 IRP proceeding, MPSC matter U-20471 and DTE's 2023 IRP proceeding, MPSC matter U-21193; DTE's Energy Waste Reduction (EWR) proceeding, MPSC matter U-20373; DTE's Voluntary Green Pricing (VGP) proceedings, MPSC matters U-20713 U-20851, and U-21172; DTE's Prepay proceeding, MPSC matter U-21087; and DTE Gas's Rate Case, MPSC matter U-21291.

We Want Green, Too intervened in DTE's 2022 Rate Case, MPSC matter U-20836; DTE's 2023 IRP, MPSC matter U-21193; and DTE's 2023 VGP filing, MPSC matter U-21172; and DTE Gas's Rate Case, MPSC matter U-21291. We Want Green, Too has worked collectively with Soulardarity to raise the issues described above.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is twofold: (1) to provide a critical analysis of DTE Electric's rate case proposal through the lens of a just and equitable energy transition, and (2) to make specific recommendations on revenue requirement and programmatic changes that would increase equity in affordability, infrastructure quality, health, and technology access.

Q: How is your testimony structured?

A: My testimony is organized into the following sections:

I. Introduction and Summary;

II. Principles of Analysis;

III. DTE Electric's Rate Case Proposal is Unjust, Unreasonable, and Insufficient to Achieve a Just and Equitable Energy Transition;

IV. Conclusion and Summary of Recommendations

Q: Are you sponsoring any exhibits?

A: Yes, I am sponsoring the following exhibits:

DAO-1. DTE Energy, 2023 Form 10-K (2024).

DAO-2. Dan Lowrey, *Electric beats gas in exceeding authorized equity returns over past 15 years,* S&P GLOBAL (May 23, 2023), https://www.spglobal.com/marketintelligence/en/news-insights/research/electric-beats-gas-in-exceeding-authorized-equity-returns-over-past-15-years.

DAO-3. Brian Allnutt, *The battle against Michigan power outages yields little accountability*, PLANET DETRIOT (Mar. 1, 2024), https://planetdetroit.org/2024/03/dte-power-outages/.

DAO-4. Fisher, Sheehan, & Colton, Michigan Energy Affordability Gap (2022)

DAO-5. DTE Electric Company's First Partial Response to DAADO-3.1.

DAO-6. DTE Electric Company's Response to DAADO-1.35, 1.36, 1.37.

DAO-7. DTE Electric Company's First Partial Response to Detroit Area Advocacy Organizations' Third Discovery Request, DAAODE-3.2a, 3.2b, 3.2.c, 3.2.d, and 3.3.

DAO-8. BEN STACEY & TONEY REAMES, URB. ENERGY JUST. LAB, SOCIAL EQUITY IN STATE ENERGY POLICY: INDICATORS FOR MICHIGAN'S ENERGY EFFICIENCY PROGRAMS (2017).

DAO-9. Amy Lange & Jack Nissen, Affordability Connectivity Programs at Risk in Detroit and Abroad without Congressional Help, *FOX 2 DETROIT* (Apr. 3, 2024), https://www.fox2detroit.com/news/affordability-connectivity-program-at-risk-in-detroit-and-abroad-without-congressional-approval.

DAO-10. WE THE PEOPLE MICHIGAN, GENTRIFICATION, POPULATION CHANGE, AND ELECTRIC GRID INVESTMENT (July 2023) (available at https://wethepeoplemi.org/wp-content/uploads/2023/08/DTE-Gentrification-Brief.pdf).

DAO-11. Edison Electric Institute, About, accessed July 26, 2024, https://www.eei.org/about-eei/About

DAO-12. Edison Electric Institute, U.S. Investor-Owned Electric Companies, accessed July 26, 2024, https://www.eei.org/about-eei/us-investor-owned-electric-companies

DAO-13. Edison Electric Institute, Member List, https://www.eei.org/-/media/Project/EEI/Documents/About/memberlist_print.pdf?la=en&hash=D5E71B7A813022B20243C1FFAD5C4170D91FFA4B

DAO-14. COMMENT FROM THE EDISON ELECTRIC INSTITUTE ON THE ENVIRONMENTAL PROTECTION AGENCY'S PROPOSED RULE NEW SOURCE PERFORMANCE STANDARDS FOR GREENHOUSE GAS EMISSIONS FROM NEW, MODIFIED, AND RECONSTRUCTED FOSSIL FUEL-FIRED ELECTRIC GENERATION UNITS; EMISSIONS GUIDELINES FOR GREENHOUSE GAS EMISSIONS FROM EXISTING FOSSIL-FUEL FIRED ELECTRIC GENERATION UNITS; AND REPEAL OF THE

		AFFORDABLE CLEAN ENERGY RULE, Docket No. EPA-HQ-OAR-2023-0072, (August 8, 2023) https://www.eei.org/-/media/497F22CE3B0D45619E5ABA593778C641.pdf.
	DAO-15.	Edison Electric Institute, Energy Grid, accessed July 26, 2024, https://www.eei.org/issues-and-policy/energy-grid
	DAO-16.	Edison Electric Institute, Electric Transportation, accessed July 26, 2024, https://www.eei.org/issues-and-policy/electric-transportation
	DAO-17.	Edison Electric Institute, Clean Energy, accessed July 26, 2024, https://www.eei.org/issues-and-policy/clean-energy
	DAO-18.	Edison Electric Institute, 2024 Lobbying, Advocacy, and Other Expenditures (February 2024).
	DAO-19.	Walker Orenstein, Utility regulators hosted annual conference in Minneapolis with money, STAR TRIBUNE (Jun. 18, 2024), https://www.startribune.com/walker-orenstein/11331478/.
	DAO-20.	Energy and Policy Institute, Utilities' Anti-Solar Campaign and Misinformation Debunked, accessed July 26, 2024, https://energyandpolicy.org/utilities-anti-solar-campaign-and-misinformation-debunked/
	DAO-21.	William Pentland, Disruptive Deceptions: How Electric Utilities Stifled Rooftop Solar, Forbes (Dec. 4, 2015), https://www.forbes.com/sites/williampentland/2015/12/04/disruptive-deceptions-how-electric-utilities-stifled-rooftop-solar/
	DAO-22.	Kim Riley, EEI takes targeted strike at EPA's power plant emissions rule, Daily Energy Insider (May 22, 2024), https://dailyenergyinsider.com/featured/43843-eei-takes-targeted-strike-at-epas-power-plant-emissions-rule/

DAO-23. Emily L Williams et al., The American electric utility industry's role in promoting climate denial, doubt, and delay, 17 Environmental Research Letters 1 (2022)

DAO-24. Matt Kasper, Coal and utility interests ask for, receive, bailouts to help failing power plants, Energy and Policy Institute (Oct. 2, 2017), https://energyandpolicy.org/bailouts-for-coal-and-nuclear-plants/.

DAO-25. *In re Xcel Energy Inc.*, Minnesota Public Utilities Commission Docket Nos. G002/GR-23-413, Bhosale Rebuttal Testimony (May 29, 2024)

DAO-26. *In re Xcel Energy Inc.*, Minnesota Public Utilities Commission Docket Nos. G002/GR-23-413, Settlement Agreement (June 26, 2024)

DAO-27. DAAODE-3.13b and DAAODE-3.14ai

DAO-28. DAAODE-3.15ai

II. Principles of Analysis

Q: What are the guiding principles of your analysis of DTE Electric's rate case proposal?

A: My analysis is guided by: (1) the application of a Social Interest Principle rather than a Profit Maximization Principle, and (2) the goal of a just and equitable energy transition. I will define and explain these principles in this section of testimony.

A. Social Interest Principle vs. Profit Maximization Principle

Q: How does DTE Electric describe their business purpose?

A: DTE Electric Witness Crozier states that "DTE Electric strives to provide safe, reliable, and affordable electric service to its customers….[and] seeks to deliver reasonable and

appropriate compensatory returns to DTE Energy shareholders while maintaining the Company's financial health."[1]

Q: How would you describe DTE Electric's business purpose?

A: Consistent with my assessment of DTE Gas in Case U-21291, I would describe DTE Electric's true business purpose as maximizing long-term profitability for DTE Energy shareholders.

As a subsidiary of DTE Energy, a publicly-traded, investor-owned corporation, DTE Electric is ultimately beholden to its parent company's fiduciary duty to maximize returns for shareholders. While DTE Electric may pursue safe, reliable, clean, and cost-effective service to some degree, it will only do so to the extent that regulation and public pressure would otherwise limit its ability to prioritize profits.

DTE Energy's own public filings confirm this profit-driven purpose. In its most recent annual 10-K filing with the Securities and Exchange Commission, DTE Energy states: "DTE Energy's strategy is to achieve long-term earnings growth with a strong balance sheet and an attractive dividend."[2]

So, while DTE Electric's testimony may mention customer service, the company's real-world behavior and legal obligations reveal that shareholder profits take precedence. As long as DTE Electric remains an investor-owned utility, regulators and the public must scrutinize its proposals and actions through this lens of profit maximization.

[1] Crozier Direct Testimony at 20, lines 7–10.
[2] Ex. DAO–1, DTE Energy, 2023 Form 10-K (2024), at 28.

Q: What evidence supports your claim that DTE Electric's business objective is maximization of long-term profit for shareholders?

A: There are several pieces of evidence that support my assessment of DTE Electric's true business objective. First, DTE Electric's parent company, DTE Energy, is an investor-owned corporation. Investor-owned utilities have a fiduciary duty to maximize returns for their shareholders. This is a well-established principle of corporate law, as articulated in cases like *Dodge v. Ford Motor Co.* (204 Mich. 459, 507; 1919).

Second, DTE Energy's own public statements emphasize profitability and shareholder returns as the company's top priorities. In its 2023 Form 10-K filing, DTE Energy states: "DTE Energy's strategy is to achieve long-term earnings growth with a strong balance sheet and an attractive dividend."[3] This focus on earnings, financial strength, and dividends reveals the company's true objectives.

Finally, DTE Electric's behavior in past rate cases and regulatory proceedings consistently prioritizes shareholder interests over customer needs. For example, in Case U-20836, DTE Electric sought a return on equity of 10.25%,[4] significantly higher than the national average for electric utilities,[5] while simultaneously requesting a substantial rate increase.[6]

Taken together, this evidence paints a clear picture: DTE Electric is ultimately beholden to DTE Energy's investor-driven business model that puts profits first. While the company's testimony may mention customer service, its ownership structure,

[3] *Id*.
[4] *In Re DTE Electric*, Direct Testimony of Jackson Koeppel, MPSC Case No. U-20836, at 84, line 21.
[5] Ex. DAO–2, Dan Lowrey, *Electric beats gas in exceeding authorized equity returns over past 15 years,* S&P GLOBAL (May 23, 2023), https://www.spglobal.com/marketintelligence/en/news-insights/research/electric-beats-gas-in-exceeding-authorized-equity-returns-over-past-15-years.
[6] Koeppel Direct Testimony, Case No. U-20836, at 84, lines 19–23.

executive incentives, and actual behavior reveal that shareholder returns are the true priority. Regulators must keep this fundamental profit motive in mind when evaluating any of DTE Electric's claims or proposals.

Q: Please describe the Profit Maximization Principle and Social Interest Principle as you will use them in your testimony.

A: The Profit Maximization Principle (PMP) refers to the guiding objective behind all elements of DTE Electric's filing: the maximization of long-term profits for DTE Energy shareholders. This principle stems from DTE Electric's obligations as an investor-owned utility to deliver returns for its parent company's investors above all else. In this case, consistent with the PMP, DTE Electric proposes a plan to maximize profitable capital investment in the gas system without regard for the long-term, systemic impacts of doing so on its customer base, and especially on low-to-moderate income (LMI) and Black, Indigenous, and People Of Color (BIPOC) communities.

In contrast, the Social Interest Principle (SIP) represents an alternative guiding objective: maximizing collective social welfare by thoroughly evaluating the full lifecycle costs and benefits of energy decisions and equitably distributing those costs and benefits. The SIP prioritizes metrics like public health, environmental sustainability, energy affordability, and community resilience over narrow measures of shareholder returns. Applying the SIP would require DTE Electric to justify its proposals based on their holistic, long-term impact on ratepayers and society, not just their effect on the company's bottom line.

In practice, the conflict between the PMP and SIP is stark. DTE Electric's proposed residential rate increase in this case exemplifies the PMP in action. The company is seeking to raise costs for essential electric service, disproportionately burdening low-income households, in order to bolster returns for shareholders—despite the fact that electricity is already unaffordable for many ratepayers and service to support those ratepayers is already deficient.[7] An SIP-driven approach, on the other hand, would prioritize reducing energy burdens and ensuring affordable access to basic service, even if it meant accepting lower near-term profits.

Q: How does your assessment of an accurate description of DTE Electric's business purpose inform your testimony?

A: My assessment that DTE Electric's true business purpose is to maximize profits for shareholders fundamentally shapes my perspective on the company's proposals in this rate case and beyond.

Recognizing that DTE Electric is ultimately driven by the Profit Maximization Principle means that I do not accept the company's claims of prioritizing customer welfare or the public interest at face value. Instead, I presume that each element of DTE Electric's testimony is oriented towards the goal of profit maximization first and social welfare to the extent that it is seen as supportive of profit maximization.

This lens of profit maximization also informs my evaluation of DTE Electric's past behavior and the credibility of its commitments to issues like affordability, reliability, and environmental responsibility. I consider how the company's actions and

[7] Kinkhabwala Direct Testimony at 6, lines 1–8; Jacob Direct Testimony at 7, lines 1–12.

investments have consistently prioritized its bottom line over the needs of its most vulnerable customers, and I view its pledges of future improvements with skepticism unless backed by clear, enforceable metrics and accountability measures.

Ultimately, my understanding of DTE Electric's profit-driven business model leads me to conclude that it is the Commission's responsibility to ensure that the utility serves the broader social interest. Throughout my testimony, I strive to provide analysis and recommendations that will help the Commission fulfill this critical role of aligning DTE Electric's behavior with the principles of affordability, reliability, sustainability, and equity, even and especially when doing so conflicts with the company's narrow financial objectives.

Q: How does DTE Electric attempt to connect the Company's "financial health" to with benefits to "customers and the region?

A: DTE Electric Witness Crozier argues that the company's strong financial health benefits customers and the broader service territory. Witness Crozier asserts that continued implementation of infrastructure maintenance and investment programs enabled by robust finances leads to benefits like job creation, economic development, and property tax payments.[8] DTE Electric separately argues that by improving its financial health—which in this case appears to deal substantially with its rate of profit—customers in fact save money by the avoidance of higher financing costs.[9]

[8] Crozier Direct Testimony at 22, lines 6–7.
[9] *Id.* at 21, lines 6–7.

Q: Does DTE adequately support its claim that the company's financial health is important to customers?

A: No. DTE Electric's claim that its financial health is necessary to benefit customers is flawed and contradictory.

The core of the company's argument is that strong financial performance allows it to make investments that improve service quality and reliability for customers.[10] However, DTE Electric is simultaneously arguing that it must raise rates - thereby reducing affordability for all customers—in order to maintain this financial health.

In essence, DTE Electric is saying that in order to avoid rates becoming even more unaffordable in the future and allowing service to become more deficient in the future, it must make rates more unaffordable now in order to secure higher profits for shareholders. This tenuous and circular logic amounts to arguing that the company must burn down the village in order to save it.

Moreover, as I will discuss later in my testimony, DTE Electric has failed to provide a convincing plan for improving affordability and reliability – let alone doing so equitably - even with the requested rate increase. The company's lack of clear commitments or strategies for delivering measurable benefits to customers further undercuts its claim that strong financial health is necessary or sufficient for promoting public welfare.

Instead of accepting DTE Electric's vague assertions about the importance of its "financial health," the Commission should demand concrete evidence that the company is

[10] Crozier Direct Testimony at 21, lines 13–23.

using its financial resources to address the real-world needs and challenges facing its customers - especially those struggling with unaffordable bills and unreliable service.

Q: Does DTE adequately explain how its business activities generate additional benefits to "customers and the region?"

A: No. As with its arguments about financial health, DTE Electric's claims about the broader economic benefits of its business activities are incomplete and unpersuasive.

Witness Crozier provides a high-level overview of the ways in which DTE Electric's operations create jobs, spur economic development, and generate tax revenue.[11] However, DTE offers no quantitative analysis or specific evidence demonstrating the scale or unique nature of these benefits.

Crucially, Witness Crozier does not show that the alleged economic benefits of DTE Electric's activities are significantly greater than what could be achieved through alternative utility structures, such as municipalization or cooperatives. Witness Crozier simply asserts that the provision of utility services generates economic activity, without addressing why DTE's role as the provider of that service is essential to that activity.

Witness Crozier also does not provide evidence demonstrating that these benefits are directly tied to DTE Electric's profitability or rate of return. Witness Crozier also fails to demonstrate that DTE Electric is uniquely capable of delivering these benefits compared to alternative utility models, such as a public or cooperative utility, or by 3rd party or community-based energy service providers.

[11] Crozier Direct Testimony at 22, lines 9–21.

This lack of comparative analysis is a critical flaw in DTE Electric's argument. The mere fact that the company's operations have some economic impact on its service territory does not serve any evidentiary purpose in justifying the importance of its profitability.

B. Just & Equitable Energy Transition

Q: Please summarize the Just and Equitable Energy Transition framework utilized by DAAO in this case.

A: The Just and Equitable Energy Transition framework employed by the DAAO in this case focuses on three central pillars:

(1) Affordability: This refers to the cost of energy service in relation to household income. A just and equitable transition requires that all households can access the energy they need to maintain health, safety, and comfort without sacrificing other essential needs.

(2) Infrastructure Quality: This encompasses the reliability, safety, and technological readiness of the energy system. A just and equitable transition demands that all communities have access to modern, resilient infrastructure that provides consistent, high-quality service. Indicators include measures of outage frequency and duration, safety incidents, and the deployment of advanced technologies like distributed energy resources and grid automation.

(3) Technology Access: This refers to the ability of households and communities to participate in and benefit from emerging clean energy technologies and programs. A just and equitable transition ensures that all ratepayers, especially those in historically

underserved areas, can access options like energy efficiency, distributed solar, battery storage, and electric vehicle infrastructure. Metrics include the penetration of these technologies in low-income and marginalized communities, as well as the availability of targeted incentives and financing mechanisms.

This framework recognizes that these three pillars are interconnected and interdependent. Efforts to improve one dimension of energy equity must not come at the expense of the others. For example, investments in advanced infrastructure should not be funded through regressive rate designs that exacerbate affordability challenges. Similarly, programs to expand clean energy access must be paired with bill protections and other measures to ensure that participating households are not left worse off.

Critically, the Just and Equitable Energy Transition framework is grounded in the lived experiences and priorities of frontline communities - those that have been most impacted by fossil fuel pollution, disinvestment, and energy insecurity. The framework highlights the need for robust community engagement, participatory planning processes, and accountability measures to ensure that these communities are not just passive recipients of energy policies, but active agents in shaping a more equitable and sustainable future.

By applying this holistic, community-centered framework to DTE Electric's rate case and other regulatory proceedings, DAAO aims to center considerations of justice, equity, and inclusion in the clean energy transition and push back against proposals that prioritize utility profits over the public interest.

III. DTE Electric's Rate Case Proposal is Unjust, Unreasonable, and Insufficient to Achieve a Just and Equitable Energy Transition

Q: Please summarize the deficiencies in DTE Electric's proposal in this case.

A: I will focus on the following deficiencies in DTE Electric's rate proposal:

- DTE Electric's proposed residential rate increase is unjust, lacks an affordability analysis, and will exacerbate the existing affordability crisis faced by many low-income and marginalized communities in DTE Electric's service territory;
- DTE Electric's proposed minimization of fiscal accountability for outages removes its incentive to improve and burdens ratepayers for its poor performance;
- DTE Electric's IT Capital requests, particularly regarding Collections Self-Service, are imprudent, driven by perverse incentives, and unlikely to achieve improvements in customer experience;
- DTE Electric's deficient study of the impact of Time-of-Use (TOU) rates fails assess impacts on low-income and other vulnerable customer groups;
- DTE Electric's equity analysis of its infrastructure spending and reliability performance is flawed and contradicts its rationale supporting the City of Detroit Infrastructure (CODI) expenditures;
- DTE Electric's request to recover discretionary corporate memberships and other industry association dues are not adequately justified in terms of benefits to ratepayers and, in some cases, are demonstrably contrary to ratepayer interests.

A. DTE Electric's proposed residential rate increase is unjust, lacks an affordability analysis, and will exacerbate the existing affordability crisis faced by many low-income and marginalized communities in DTE Electric's service territory

Q. How much does DTE Electric's proposed rate hike impact residential ratepayers?

A. DTE Electric is proposing a $456.4 million rate increase, with residential customers seeing a 9.6% increase in their rates under the proposed plan.[12] This would amount to an additional $11.25 per month for a typical residential customer.[13] This increase, on top of the consistent increases the Commission has approved in the past few rate cases, would continue to exacerbate the unaffordability of DTE's rates and harm already overburdened LMI and BIPOC communities.

Q. How does the Commission define affordability?

A. The Michigan Public Service Commission has defined energy affordability as "the extent to which a household has the resources to meet their home energy needs for heating, cooling and other uses in a healthy, sustainable, and energy efficient manner without compromising a household's ability to meet other basic needs."[14]

This definition recognizes that affordability is not just about the absolute cost of energy, but about the ability of households to pay for necessary energy services while still meeting other essential needs like food, housing, healthcare, and transportation. It

[12] MPSC Case No. U-21534, Rate Case Summary, (Mar. 25, 2024), available at https://mi-psc.my.site.com/s/filing/a008y000004RHVEAA4/u215340002, at 4.

[13] *See* Crozier Direct Testimony at 17, lines 4–7 (stating that the rate request would result in an increase in the average customer bill of 37 cents a day). Thirty-seven cents times 365 days is $135.05 per year, divided by 12 is $11.25 per month.

[14] *In re Response to COVID-19*, MPSC Case No. U-20757, Order (Dec. 21, 2023) [hereinafter U-20757 Order], available at: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000BD37gAAD, at 36.

also emphasizes the importance of energy efficiency and sustainability in promoting long-term affordability and reducing environmental impacts.

Q. What is energy burden and how does it relate to affordability?

A. Energy burden is defined as the percentage of household income spent on energy.[15] Energy burden is a key metric for assessing energy affordability as it directly measures the impact of energy costs on household budgets and the ability to meet other basic needs.

As discussed in greater depth by DAAO Witness Justin Schott, energy burdens in Michigan are particularly high for low-income households. As of 2022, households at or below 50% of the federal poverty level faced an average energy burden of over 30%, while those between 50% and 100% of the poverty level had an average burden of 20%.[16] These figures highlight the urgent need for policies and programs that prioritize energy affordability for the most vulnerable customers.

Q. Does DTE Electric use the word "affordability" throughout their testimony in an internally consistent manner, or a manner consistent with the Commission's definition?

A. No, DTE Electric's testimony frequently uses the term "affordability" in ways that are inconsistent with or unrelated to the Commission's definition. DTE states that it "does not have a standard definition of affordability," but "uses the term "affordable" or "affordability" to reflect keeping customer bills as low as possible" while recovering its

[15] Direct Testimony of Witness Justin Schott at 11, line 17.
[16] *See* Ex. DAO-4, Fisher, Sheehan, & Colton, Michigan Energy Affordability Gap (2022), at 1–2.

costs.[17] This response manages to be both exceedingly vague and exceedingly troubling, in that it implies DTE Electric is fundamentally unconcerned with a customer's ability to afford energy. Instead, DTE Electric's testimony tends to use "affordability" as a generic term to describe the overall cost of service, without any meaningful consideration of the ability of different customer groups to pay for necessary energy services while meeting other basic needs. This narrow and uncontextualized view of affordability fails to capture the real-world impacts of rising energy costs on household budgets and quality of life, particularly for low-income and marginalized communities, and fails to meet the standard of the Commission's definition.

Q. Has DTE Electric presented a sufficient analysis of affordability in this case?

A. No. DTE Electric acknowledges that it did not conduct any specific analysis of customer affordability impacts or energy burdens in developing its rate case proposal. The company also did not assess how the proposed rate increase would affect the existing affordability gap for low-income customers or propose any new programs or investments specifically aimed at reducing energy burdens.[18]

Q. How does DTE Electric attempt to characterize the affordability problem?

A. DTE Electric's characterization of the affordability problem tends to downplay its severity and urgency, demonstrate a lack of real planning to address the crisis, and to prioritize the company's own financial interests over the needs of its most vulnerable customers. DTE Electric further utilizes reference to affordability to justify its proposed

[17] Ex. DAO–5, DTE Electric Company's First Partial Response to DAADO-3.1.
[18] Ex. DAO–6, DTE Electric Company's Response to DAADO-1.35, 1.36, 1.37.

investments but is unable to produce a coherent definition or measurable goals. This approach is inconsistent with the principles of a just and equitable energy transition.

Witness Crozier emphasizes that DTE Electric's proposed rate increase is necessary to support continued investments in reliability, safety, and clean energy infrastructure, which she argues will benefit all customers in the long run.[19] While some of these investments may be important, as discussed above, this framing fails to acknowledge the trade-offs and distributional impacts of raising rates on customers who are already struggling to pay their bills.

Company Witness Hatsios acknowledges that DTE Electric has seen an increase in service disconnections and arrearages in recent years.[20] However, he does not provide any specific analysis of how these affordability challenges are distributed across different customer groups or propose any targeted solutions beyond existing assistance programs and payment plans. Additionally, Company Witness Sharma refers to "affordability targets,"[21] but was unable to produce any such targets in response to discovery.[22]

Q. What should the Commission do to work toward improving affordability?

A. The Commission should require that DTE Electric adopt and uniformly use the Commission's definition of affordability, set energy-burden based goals to improve the company's unaffordable rates, and refrain from using the term in the incoherent manner

[19] Crozier Direct Testimony at 15–16.
[20] Revised Direct Testimony of Witness Hatsios at 23, lines 6– 9 (stating that shutoff notices increased from 1.9 million in 2022 to 2.1 million in 2023, and that there was a 28% increase in low-income customers reaching final arrears status in 2023).
[21] Revised Direct Testimony of Witness Sharma at 31, lines 14–16.
[22] Ex. DAO–7, DTE Electric Company's First Partial Response to Detroit Area Advocacy Organizations' Third Discovery Request, DAAODE-3.2a, 3.2b, 3.2.c, 3.2.d, and 3.3.

that has been the company's practice. Additionally, the Commission should require DTE Electric to conduct a comprehensive affordability assessment as part of its next rate case filing, using the Commission's affordability definition and metrics to evaluate the impact of proposed rates and investments on energy burdens and other key indicators. This assessment should include a detailed analysis of affordability gaps and disparities across different customer groups and geographic areas, as well as specific proposals for how to mitigate these impacts and support more equitable outcomes.

Q. Do you have any further recommendations to the Commission regarding the provision of affordability?

A. Yes. I believe the Commission should consider the immediate implementation of affordability-based rates through an operating expense in DTE Electric's revenue requirement.

Q: Describe your proposal for affordability-based rates.

A: The affordability gap for electricity bills in DTE Electric territory is about $380 million. After accounting for existing affordability programs, an additional $304 million is required to close the affordability gap. Witness Makhikani estimates that per DTE Electric's sales projection, a rate increase of 0.743 cents per kilowatt hour of energy sold would close this gap.[23] I recommend this amount be included in the revenue requirement, added equally to all bills, and utilized to cover the affordability gap for all customers.

[23] Makhikani Direct Testimony at 28, lines 4-8.

Q: How do you envision such a program being implemented?

A: If a DTE Electric customer falls behind in their bills, they would be contacted by DTE Electric. DTE Electric would verify their income, compare it to their last twelve months of bills, and identify if their cost of electricity exceeded 6% of their annual income. If so, DTE Electric would immediately credit to their account the amount accrued in excess of that number. DTE Electric would then calculate the percentage of that customer's bills which were in excess of the affordability threshold and begin applying a monthly affordability credit at that percentage rate moving forward.

In the initial program year, DTE Electric would be granted an operating revenue increase marched to the affordability estimates presented in Witness Kinkhabwala. Every year thereafter, DTE Electric would file a reconciliation report with the total amount of affordability credit offered with a request for recovery. Recovery would be contingent upon DTE Electric demonstrating its best efforts to support customers to access existing assistance programs and implementation of the cost-reducing measures identified in Witness Kinkhabwala's testimony.

Q: How does this proposal align with your position to avert a residential rate hike?

A: While I believe reductions in the company's shareholder profits would be appropriate, the limitation of further harms does not address the existing affordability crisis. In order to do so, a more comprehensive affordability program is needed. I understand that the proposal above would result in a rate increase in the most literal sense. However, the increase would serve primarily to socialize the cost of unaffordable power and would immediately—and durably—end the affordability crisis.

Q: Why are you proposing this issue be solved within the rate structure rather than through additional public spending?

A: First, addressing the affordability crisis in the rate structure directly changes how DTE Electric does business and engages with customers. The excessive, cruel, and costly collections practices which DAAO has fought against for years and have been further elucidated by Witness Jacob would all but disappear. Second, this proposal would not require legislative action; resolving the affordability crisis through rate structure would offer a complete affordability solution within the context of regulatory intervention. Finally, the process of financial reconciliation of recovery requests by DTE Electric presents a unique opportunity to tie affordability and equitable energy transition together through thoughtful performance metrics.

B. DTE Electric's proposed minimization of fiscal accountability for outages removes its incentive to improve and burdens ratepayers for its poor performance

Q. What does DTE Electric request regarding outage credits?

A. In this rate case, DTE Electric is proposing several changes to its existing outage credit mechanism that would reduce the company's financial liability for service interruptions and shift more of the costs and risks of outages onto ratepayers. Specifically, DTE Electric is proposing to modify the criteria for determining which outage credits are eligible for recovery by the company by denoting certain types of outages that the

company deems to be "outside of DTE Electric's control," such as those caused by the transmission operation, public interference, animal interference, and weather.[24]

Q. How does DTE justify its request to limit its financial accountability for outages?

A. Witness Crozier cites the Commission's order in Case No. U-20836. In that case, the Commission approved the ALJ's recommendation to adopt MPSC Staff's proposals to allow DTE to recover the cost of outage credits for outages with certain causes that were outside DTE's control, such as outages caused by customer negligence or the transmission system operator.[25] Witness Crozier then proposes that the outages for which DTE can recover the costs of outage credits be broadened beyond what the Commission stated in that case to include a number of additional scenarios including outages caused by animal interference and outages caused by weather.[26]

Q. What is your view of DTE Electric's request to minimize their financial accountability for outages?

A. I am strongly opposed to DTE Electric's proposed changes to its outage credit mechanism, as I believe they would undermine the fundamental purpose of outage credits as a tool for holding utilities accountable for providing reliable service to their customers.

Outage credits are intended to serve several important functions in the regulatory compact between utilities and their customers. First and foremost, they are a way of compensating customers for the inconvenience, disruption, and economic losses they

[24] Crozier Direct Testimony at 31–33.
[25] *Id*. at 31–32 (citing MPSC Case No. U-20836, Order, (Nov. 18, 2022) at 366.
[26] Crozier Direct Testimony at 32–33.

suffer when their power goes out, particularly for extended periods of time. However, outage credits also serve to incentivize utility behavior that benefits ratepayers by improving reliability. By providing a financial incentive for utilities to minimize the frequency and duration of outages, outage credits help to ensure that companies like DTE Electric are making the necessary investments and operational improvements to maintain a high level of service reliability.

DTE Electric's proposed changes to its outage credit mechanism would undermine the company's incentive to improve its reliability. By allowing the company to recover the cost of outage credits for certain types of outages, the Commission would allow the company to externalize the cost of those outages. This would be particularly harmful if extended to causes such as weather and animal interference where investments made by the company could significantly reduce both the frequency and duration of the outages. If DTE chooses not to make these investments, the company, not customers, should internalize that cost.

Q. What is your recommendation to the Commission?

A. I recommend that the Commission reject DTE's proposal for deferred accounting treatment of outage credits, reject their proposed system to partially recover its already limited outage credits in the specific instances it identifies such as weather and animal interference. I further recommend that the Commission reconsider the establishment of hourly, progressive, automatic credits as DAAO has previously argued for before the Commission.[27]

[27] *See* MPSC Case No. U-21297, Revised Direct Testimony of Jackson Koeppel (July 5, 2023) at 79.

C. DTE Electric's IT Capital requests, particularly regarding Collections Self-Service, are imprudent, driven by perverse incentives, and unlikely to achieve improvements in customer experience

Q. What does DTE Electric request in terms of IT Capital expenses?

A. In this rate case, DTE Electric is requesting approval for a significant increase in its capital expenditures for information technology (IT) systems and infrastructure. Specifically, the company is seeking to justify $181.1 million in IT capital expenditures.[28]

Q. Do you have any concerns with DTE's Digital Self Service programs?

A. Yes. There are several reasons to believe that DTE Electric's proposed IT capital investments in digital self-service tools for customer collections may be subject to diminishing returns and may not generate the full scale of benefits that the company claims.

Witness Hatsios's own testimony suggests that DTE Electric may be reaching a saturation point in terms of the adoption and utilization of its self-service options by customers. For example, he notes that the company has seen a significant increase in the percentage of customer interactions and transactions that are completed through digital channels in recent years, from 53% in 2020 to almost 70% in 2023.[29] While this trend may be positive from a cost and efficiency perspective for DTE Electric, it also raises questions about how much additional room for growth and improvement there may be in

[28] Hatsios Revised Direct Testimony at 2–3. $181.1 represents the sum of the expenditures in the historical test year ending in Dec. 31, 2022 the 24-month bridge period ending in Dec. 31, 2024, and the proposed expenditures in the projected test year ending Dec. 31, 2025. *Id.*

[29] *Id.* at 18 tbl.2.

this area, particularly given the ongoing economic and technological barriers that some customers may face in accessing and using digital tools. It appears that in certain categories, such as the categories of Outages and Payment, DTE Electric is already nearing their long term targets.[30] And although Collections DERs are increasing, actual call volumes are not diminishing.[31]

It is worth noting that DTE Electric's proposed IT capital investments in digital Collections self-service for customer collections are not necessarily aligned with the broader goals and priorities of the Commission and other stakeholders in terms of advancing energy affordability, equity, and sustainability in Michigan. While improving the efficiency and convenience of the collections process may generate some cost savings and revenue benefits for DTE Electric, it does not address the root causes of customer non-payment and energy insecurity, such as high rates, inadequate assistance programs, and systemic economic and social inequities.

In fact, as discussed further below, there is a risk that DTE Electric's focus on digital self-service and automation in its collections processes could actually exacerbate these challenges by making it easier for the company to pursue disconnections and other punitive measures against struggling customers, without providing meaningful support or solutions for their underlying affordability needs. This points to the need for a more comprehensive and equity-focused approach to customer service and collections that prioritizes bill assistance, energy efficiency, and other programs that can help to reduce

[30] *Id*.

[31] *Id.* at 23, lines 3–5 (noting that call volumes are "not materially different" from levels seen four or five years ago).

energy burdens and improve access to affordable, reliable, and clean energy for all customers.

Q. What specific requests does DTE Electric make regarding IT Capital for Collections Digital Self-Service?

A. One of the specific IT capital investments that DTE Electric is seeking to recover in this rate case is $10.7 million for a new "Collections Digital Self-Service" platform, which the company claims will enhance its ability to collect on past-due customer accounts and reduce its overall bad debt expense.[32] According to Witness Hatsios, the Collections Digital Self-Service platform will include a range of new features and capabilities, such as a web portal that allows customers to request restoration of service and payment holds, and allows customers to view the status of holds, energy assistance funding, and pending income status verifications.[33]

Q. How does DTE Electric's explanation of the benefits of investment in Collections self-service capital imply a perverse incentive?

A. DTE Electric's justification for its proposed $10.7 million IT capital investment in the Collections Digital Self-Service platform reveals a troubling misalignment of incentives that prioritizes the company's own financial interests over the needs and well-being of its customers.

Witness Hatsios acknowledges that many of DTE Electric's customers are facing significant affordability challenges, including high energy burdens and economic

[32] *Id.* at 21–22.
[33] *Id.* at 22, lines 6–12.

insecurity.[34] However, rather than proposing meaningful solutions or investments to address these challenges and reduce the need for collections activities in the first place, DTE Electric is instead seeking to use ratepayer funds to make its collections process more automated, efficient, and aggressive.

This reveals a perverse incentive structure in which DTE Electric is essentially being rewarded for its own failure to ensure that its services are affordable and accessible to all customers. By investing in digital self-service tools and other technologies that make it easier and cheaper for the company to pursue collections and disconnections, DTE Electric is effectively shifting the costs and risks of its own unaffordable rates onto its most vulnerable customers, while generating additional profits for its shareholders through increased capital spending.

This is particularly concerning given the ongoing affordability crisis facing many low-income and marginalized communities in Michigan, and the disproportionate impacts of energy insecurity and utility shut-offs on these groups as discussed by DAAO Witnesses Schott, Jacob, Kinkhabwala, and Makhijani. By focusing on collections efficiency rather than affordability and assistance, DTE Electric is not only failing to meet its basic obligations as a regulated utility, but is actively exacerbating the economic and social inequities that are at the root of the problem.

[34] *See id.* at 23, lines 5–9 (stating that, between 2022 and 2023, there was an "11% increase in the number of active low-income customers versus 2022, a 28% increase in the number of low-income customers who reached final arrears status, a 15% reduction in available Energy Assistance (EA) funding, and an increase in shutoff notices from 1.9 million to 2.1 million").

Q. Do you see any value in these investments in digital self-service?

A. Yes. In general, I think that improving these systems is beneficial to customers. However, I think that it is unlikely to generate the sort of call volume reduction DTE claims. Further, to whatever extent it does reduce call volume, I expect that difficulty navigating affordability issues for customers would increase. These investments should thus not be paired with the expectation that other more personal methods of customer support during outages and affordability crisis would be reduced; rather, digital self-service should be considered to be complementary to call support. Any digital self-service capital investment should also be paired with performance metrics aimed at reducing the indicators of customers experiencing affordability crises, such as disconnections or shutoff notices.

Q. What do you recommend to the Commission?

A. I recommend that the Commission reject DTE Electric's request to recover the $10.7 million in costs associated with the Collections Digital Self-Service platform at minimum, as well as any other proposed IT investments that are primarily focused on collections automation and efficiency rather than customer assistance and affordability. Furthermore, I recommend that the Commission require DTE Electric to provide a more detailed and comprehensive cost-benefit analysis of its IT investments, including specific metrics and targets for reducing energy burdens, preventing disconnections, and improving customer satisfaction and affordability, particularly for low-income and vulnerable households. I also support all of the recommendations in Witness Jacob’s testimony.

D. DTE Electric's deficient study of the impact of Time-of-Use (TOU) rates fails assess impacts on low-income and other vulnerable customer groups

Q. What action does DTE Electric request regarding conversion to TOU rates in this case?

A. In this case, DTE Electric is proposing several changes to its residential rate offerings that would expand the availability and adoption of Time of Use (TOU) rates, while phasing out some of its existing flat-rate options. Specifically, the company is requesting to (1) change the Low Income Assistance (LIA) policy that currently requires customers to switch from their existing rate schedule to D1.6, to all residential base rates[35] (2) transition the remaining customers on the closed D1.6 rate, a product available to qualifying low-income customers and supplies them with a $40 monthly credit, to the D1.11 rate, which is a TOU rate with peak and off-peak pricing periods,[36] and (3) Retire the D1.6 rate entirely once all customers have been migrated to other rate options.[37]

According to DTE Electric Witness Willis, these changes are intended to provide "optionality" to LIA-recipient customers.[38] Willis argues that TOU rates can benefit both customers and the grid by incentivizing energy use during off-peak periods when electricity is less expensive to generate and deliver, and by reducing demand during peak periods when the system is under the most stress.[39]

[35] Willis Revised Direct Testimony at 22, lines 1–4.
[36] *Id.* at 18, lines 6–7, 15–17; *id.* at 22, lines 6–11.
[37] *Id.* at 22, lines 12–15.
[38] *Id.* at 22–23.
[39] *Id.* at 23–24.

Q. What did DAAO argue for regarding DTE Electric's proposed retirement of the D1.6 rate class in MPSC Case No. U-21297?

A. In the last rate case (case no. U-21297), DAAO argued that the Commission should reject the company's request to retire the D1.6 rate schedule, and move customers currently paying D1.6 rates to the D1.11 rate, until after the company had completed a study of the impacts of such a shift.[40] Specifically, DAAO requested that the Commission require the company to conduct a study with the following parameters:

1. "Compare the rate of customer disconnections (1) for all customers switched to TOU rates before and after they were switched, (2) for all LMI customers who were switched to TOU rates before and after they were switched, and (3) for all customers on the D1.6 rate before and after DTE implemented the TOU rate for its other customers.
2. Survey customers to identify measures likely to contribute to being unable to shift energy use off of peak times (e.g., family size, having a disability, having children and elders, having all working parents).
3. Run three different regressions analyzing the impact both before and after the implementation of the U-20836 order, including the switch to TOU rates. For this analysis, DTE should identify a representative sample of ratepayers, including customers both at the same income level included in the D1.6 rate class and at income levels representing every band of income in the DTE service territory. The sample of LMI ratepayers should include customers on the D1.6 rate class and those who were already shifted to TOU. For the regressions run for the D1.6 rate class customers, the

[40] *See In re DTE Electric Co.*, MPSC Case No. U-21297, DAAO Replies to Exceptions (Nov. 8, 2023) [hereinafter U-21297 DAAO Replies to Exceptions] at 7–10.

categories should include the D1.6 rate class customers, only customers who went through the TOU switch, and those two groups combined to generate appropriate comparisons."[41]

Q. What did the Commission order regarding the retirement of the D1.6 rate class and conversion to time of use rates in U-21297?

A. In its order in Case No. U-21297, the Commission agreed with DAAO's concerns about the company's proposal to retire the D1.6 rate and transition all low-income customers to the D1.11 TOU rate.[42] Specifically, the Commission agreed that DTE Electric had not provided any detailed studies or modeling to demonstrate how different types of low-income customers with different usage patterns and household characteristics would be impacted by the transition to TOU rates, or to identify any potential unintended consequences or disparate impacts that could result from this change.[43]

To address these concerns, the Commission directed DTE Electric to conduct a study of the potential impacts of TOU rates on low-income customers before proposing to retire the D1.6 rate or transition these customers to other rate options:

> The Commission remains supportive of TOU rates; however, the Commission agrees with the DAAOs and finds it appropriate for DTE Electric to conduct an impact study comporting to the DAAOs' recommended report outline before retiring Rate Schedule D1.6 and transitioning customers to Rate Schedule D1.11. The Commission thus finds that Rate Schedule D1.6 should continue at this time,

[41] *Id.* at 8–9.
[42] *In re DTE Electric Co.*, MPSC Case No. U-21297, Order (Dec. 1, 2023) [hereinafter U-21297 Order] at 312–13.
[43] U-21297 Order at 309–10.

with this issue to be revisited in the company's next rate case and with results from the company's study to help inform the appropriate path forward.[44]

Q. Has DTE Electric completed a TOU study which meets the terms of the order?

A. No, based on the information provided in DTE Electric's testimony and exhibits in this case, the company has not completed a TOU study that meets any of the terms and requirements of the Commission's order in Case U-21297.

Witness Willis states that DTE Electric has conducted a bill "impact study" to review the average change in monthly bills for current D1.6 who transitioned to the D1.11 TOU rate, based on data customers who switched from the D1.6 rate following the Commission's order in the U-20836 rate case.[45] According to DTE Electric witness Willis, the company's theoretical bill impact analysis found that "the average impact is near zero" from transitioning from the current D1.6 to the D1.11 TOU rate, with most customers seeing a decrease of their bill of 0.17%.[46] The study additionally found that customers "with higher average usage tend to benefit on D1.11 and customers with lower average usage tend to benefit on the inverted block rate."[47] Witness Willis concludes that "there is no structurally adverse impact" to the transition from D1.6 to D1.11 rates.[48]

However, this analysis falls short of the Commission's order in several key respects.

[44] U-21297 Order at 312–13.
[45] Willis Revised Direct Testimony at 23, lines 4–13.
[46] *Id.* at 23, lines 17–19.
[47] *Id.* at 24, lines 6–7.
[48] *Id.* at 23, lines 18–19.

First, DTE's analysis does not provide any information on the rate of shut-offs for customers that switched from the D1.6 rate to the D1.11 rate. Without providing an analysis of the rates of shut-offs for customers switched from the D1.6 rate, and comparing them to relevant control groups, DTE cannot establish that the switch would not significantly harm its LMI customers.

Second, Witness Willis provides no information from any company survey of customers to identify measures likely to contribute to being unable to shift energy use off of peak times, such as family size or disability status. Without such a survey, it is impossible to know whether vulnerable households with these characteristics are suffering under the switch to TOU rates. Regardless of whether customers on average tend to have a significant increase in cost on TOU rates, knowing whether the transition is likely to shift costs primarily to a particular group of vulnerable customers, such as those with disabilities, young children, or with multiple parents who have to work, is important before the Commission orders the retirement of the D1.6 rate. DTE's failure to provide a study with an analysis of this information means that the Commission still does not have the necessary data to approve the retirement of the D1.6 rate.

Finally, the analysis described by Witness Willis does not include a regression analysis to identify any statistically significant differences in the impacts of TOU rates on different groups of customers.

Overall, while DTE Electric has made some effort to analyze the potential impacts of transitioning low-income customers to TOU rates, this analysis falls well short of the analysis that the Commission ordered in Case No. U-21297. Without a more thorough and inclusive analysis of the potential risks and benefits of TOU rates for low-

income customers, it is premature and inappropriate for DTE Electric to propose retiring the D1.6 rate or transitioning customers to other rate options at this time.

Q. Are you opposed to time of use in principle?

A. No. In fact, I believe that well-designed TOU rates, if paired with targeted energy efficiency, demand response, and distributed energy resource (DER) programs, could potentially provide significant benefits for low-income customers and communities, by reducing energy burdens, improving affordability and resilience, and providing opportunities for local economic development and empowerment.

Additionally, the analysis presented by DTE Witness Willis points to the potential for TOU rates to serve as part of the solution to underconsumption – the pattern of low-income households severely limiting energy use even when it compromises home health and safety due to affordability challenges. The insight that higher-use customers tended to benefit on the switch to D1.11, while presenting an additional affordability burden to low-use households in the most immediate sense,[49] also highlights the potential for TOU rates to encourage usage rates that better match household needs. Witness Willis' analysis is completely inadequate to truly understand this potential, but it opens up interesting questions for further exploration.

Low-income households face a range of structural and socioeconomic barriers that make it more difficult for them to respond to TOU price signals or to take advantage of potential bill savings opportunities. These include limited flexibility in household energy use patterns due to work obligations, childcare needs, or medical conditions,

[49] *Id.* at 23–24.

lower access to energy efficiency,[50] the lack of affordable internet access[51] required for smart devices and demand response, and language or digital literacy barriers that make it harder to understand and navigate peak pricing.

Given these challenges, I believe that any consideration of TOU rates for low-income customers must be based on a thorough and equity-focused analysis of the potential impacts and risks for different subgroups of customers, and must include robust consumer protections, education and outreach programs, and other measures to ensure that vulnerable households are not unduly burdened or left behind.

Q. What do you recommend the Commission do in the instant case?

A. Based on the concerns and considerations outlined in my previous responses, I recommend that the Commission (1) reject DTE Electric's request to retire the D1.6 flat rate for low-income customers and to transition all customers to the D1.11 TOU rate at this time, and (2) require DTE Electric to conduct a more comprehensive and collaborative study of the potential impacts and opportunities of TOU rates for low-income customers, in line with the Commission's order in Case No. U-21297.

[50] Ex. DAO–8 BEN STACEY & TONEY REAMES, URB. ENERGY JUST. LAB, SOCIAL EQUITY IN STATE ENERGY POLICY: INDICATORS FOR MICHIGAN'S ENERGY EFFICIENCY PROGRAMS (2017), at 2.

[51] *See Generally* Ex. DAO–9, Amy Lange & Jack Nissen, Affordability Connectivity Programs at Risk in Detroit and Abroad without Congressional Help, *FOX 2 DETROIT* (Apr. 3, 2024), https://www.fox2detroit.com/news/affordability-connectivity-program-at-risk-in-detroit-and-abroad-without-congressional-approval.

F. DTE Electric's equity analysis of its infrastructure spending and reliability performance is flawed and contradicts its rationale supporting the City of Detroit Infrastructure (CODI) expenditures

Q. How does DTE Electric describe the equity impact of its infrastructure plans?

A. In his direct testimony, DTE Electric Witness Kryscynski describes the company's efforts to integrate equity considerations into its distribution system planning and infrastructure investment processes. Specifically, Witness Kryscynski states that DTE Electric has begun using the Michigan Environmental Justice Screen (MI EJScreen) tool, developed by the Michigan Department of Environment, Great Lakes, and Energy (EGLE), to analyze the socioeconomic and demographic characteristics of the communities served by its distribution system, and to identify areas with high concentrations of low-income, minority, and other vulnerable populations.[52] DTE relies on defining communities at the 80th percentile and above of MIEJ Screen score as "vulnerable" and running comparisons between those communities and overall system averages on various measures of system performance.[53]

Q. What are the problems with DTE Electric's equity analysis?

A. There are several problems and limitations with DTE Electric's approach to integrating equity considerations into its distribution system planning and infrastructure investment processes, as described by witness Kryscynski in his direct testimony.

While the MIEJ Screen tool is a useful starting point for identifying areas with high concentrations of low-income and vulnerable populations, it does not provide a

[52] Revised Direct Testimony of Witness Kryscynski at 78–79.
[53] *Id*. at 79.

sufficiently granular or differentiated picture of the specific needs, challenges, and opportunities facing individual neighborhoods, households, or customer subgroups within each tract.

For example, a census tract with an overall MI EJScreen about the 80th percentile may still contain significant variation and heterogeneity in terms of income levels, housing quality, energy burdens, and other relevant factors that affect customers' energy needs and vulnerabilities. Lumping all customers in this tract together under a single equity category may obscure important differences and disparities that require more targeted and customized interventions. As previously discussed by DAAO in case no. U-21297, DTE Energy's investment patterns in Detroit have prioritized census tracts which are becoming whiter and wealthier, while neighborhoods that are not experiencing the same demographic change are being left behind.[54] Conversely, census tracts which do not register above the 80th percentile likely include many households with low incomes, poor housing quality, high energy burdens, and cumulatively impacting social vulnerabilities. DTE has chosen to studiously ignore this reality.

In DTE's current mode of equity analysis, these differences continue to be flattened by a binary assessment of vulnerable vs. not vulnerable tracts. As an example, in Witness Deol's defense of the City of Detroit Infrastructure (CODI) program investments, he states:

Some of the notable new load projects in the last decade are Little Caesars Arena, David Whitney Building, Q Line Light Rail System, Wayne State School of Business and

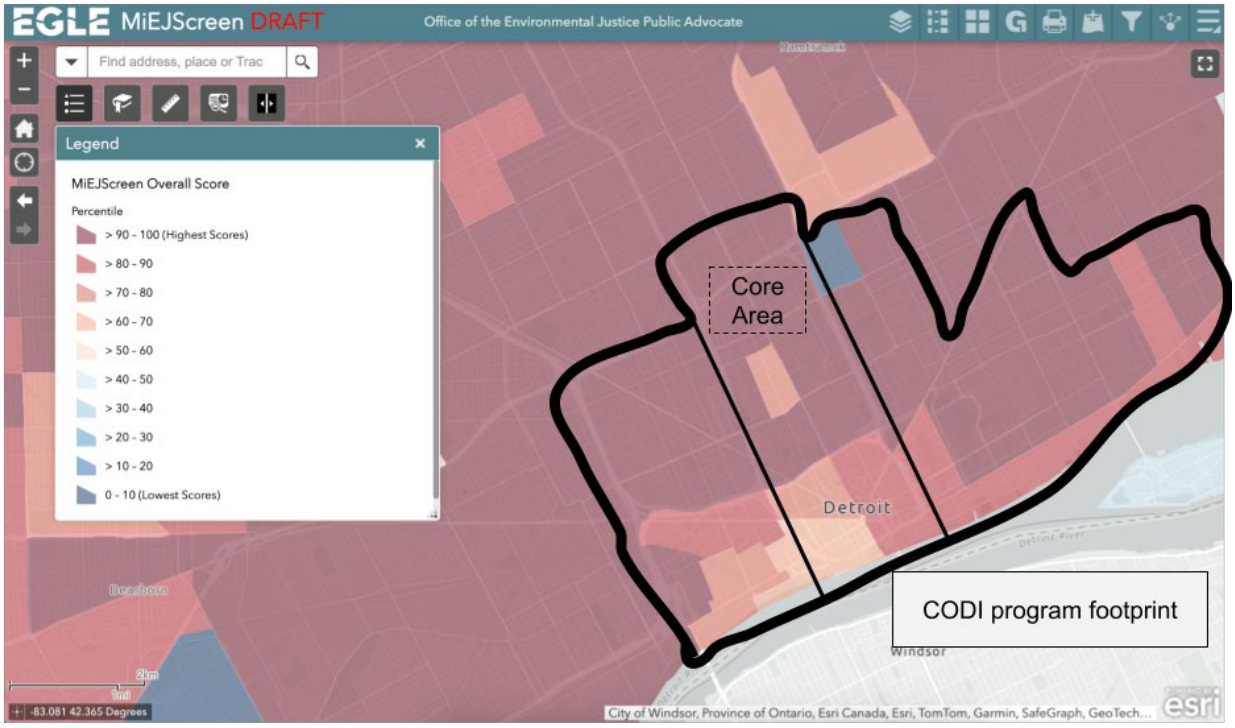
[54] *See* Ex. DAO–10, WE THE PEOPLE MICHIGAN, GENTRIFICATION, POPULATION CHANGE, AND ELECTRIC GRID INVESTMENT (July 2023) (available at https://wethepeoplemi.org/wp-content/uploads/2023/08/DTE-Gentrification-Brief.pdf).

Hillberry Theater Expansion, Book Tower, David Stott Building, Detroit Pistons Performance Center, and the Huntington Bank Tower. These along with dozens of other completed new build/renovations in the New Center, Midtown, and Central Business District areas of Detroit have created significant load growth and economic momentum in the CODI area, which will continue with the pipeline of future projects.[55]

Clearly, at least from this list of investments, Witness Deol is not primarily concerned with improving service to vulnerable populations. Yet investments in the CODI areas nonetheless likely count towards Krysycnski's binary bucketing of "vulnerable" census tracts, even if DTE directly acknowledges that these investments are primarily intended to serve new load and new residents.[56]

[55] Deol Direct Testimony at 26–27.
[56] See Figure 1 showing EJ census tracts within the CODI area.

Figure 1: MiEJScreen Grab, Economic Development and Load Growth Map[57]



Witness Krysynski presents a table in his testimony which shows higher numbers of residential customers in clusters of census tracts at higher EJ score percentiles,[58] likely indicating higher population density. In the preceding tables Krysynski presents, the EJ score census tracts at the 35th-40th percentiles and below, which have the lowest numbers of residential customers, also demonstrate the most consistent underperformance.[59] This indicates a strong potential that population density is a significant factor in reliability performance.

[57] This figure was pulled from the MIEJ Screen Website (available at https://www.michigan.gov/egle/maps-data/miejscreen). I outlined the CODI program footprint.
[58] Kryscynski Direct Testimony at 92, Table 14.
[59] *Id*. at 88–92, Tables 10, 11, 12 ,13.

Q: Does DTE Electric present a consistent position on equity in service quality?

A: No. There are notable discrepancies between the equity analysis presented by Witness Kryscynski and Witness Deol's defense of the City of Detroit Infrastructure (CODI) program.

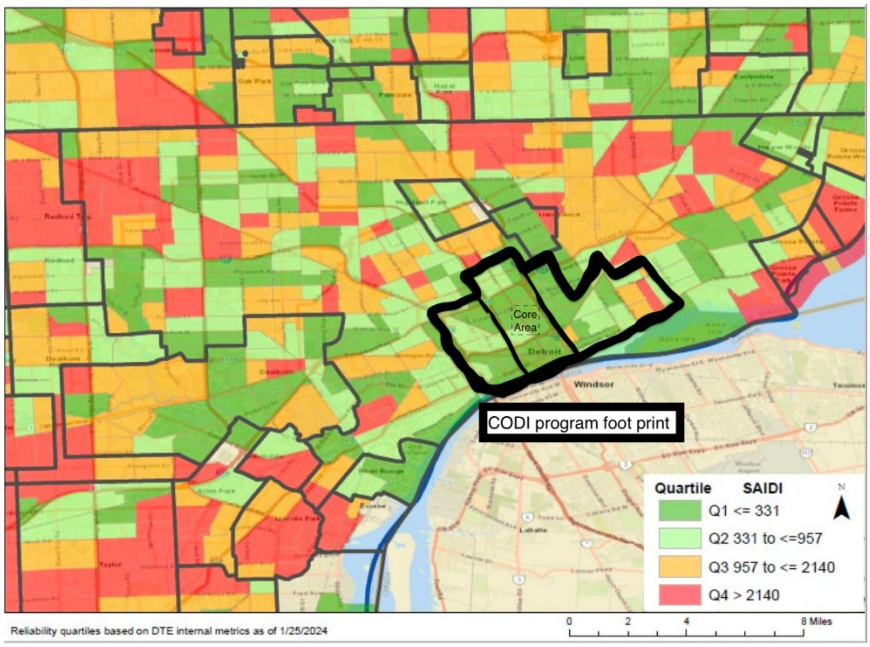
Q: Please describe the conflict between witness Krysynski and Deol's positions.

A: Witness Deol argues that the CODI program is essential because customers are experiencing much worse reliability in the target areas of the program due to load growth and aging infrastructure.[60] But to the contrary, the maps presented by Witness Kryscynski show those a substantial portion of those target areas as being in the first and second quartiles of reliability performance in 2023. This especially true of the "Core Area", which is almost entirely within the first quartile of performance.[61] DTE Electric is describing two different realities: one in which the CODI areas are in need of investment due to reliability problems, and one in which the CODI areas are part of the higher-performing EJ communities which demonstrate its equitable service. Witnesses Deol and Kryscynski use these different realities for the same end: justifying DTE's preferred capital spending plan without the integration of equity analysis into its actual development.

[60] Deol Direct Testimony at 26.
[61] Kryscynski Direct at 83, 85, Figures 13 and 15.

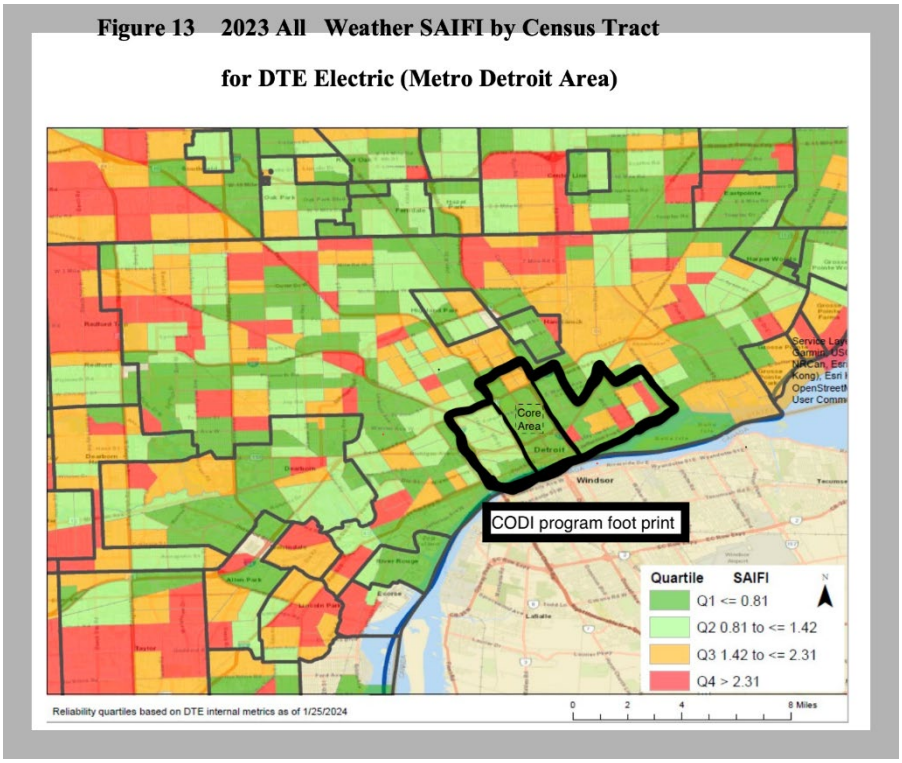
Figure 2: CODI Program Outline from SAUDI Census Tract[62]

Figure 15 2023 All Weather SAIDI by Census Tract for DTE Electric (Metro Detroit Area)



[62] This figure was pulled from Witness Kryscynski's Testimony at 85, over which I traced the CODI program footprint.

Figure 3: CODI Program Outline from SAIFI Census Tract[63]



Q. What do you recommend the Commission do in the instant case?

A. The Commission should reject or substantially reduce DTE's proposed capital spending on the CODI program, particularly in the Core Area which demonstrates higher-than-average reliability. The Commission should require DTE to analyze changes in demographics over time when assessing the equity impacts of its proposed long-term investments. Finally, the Commission should require the use of regression analysis to have a complete understanding of equity outcomes along lines of race and class.

[63] This figure was pulled from Witness Kryscynski's Testimony at 83, over which I traced the CODI program footprint.

G. Corporate memberships are not supported and are contrary to ratepayer interest

Q. What does DTE Electric request in terms of corporate memberships?

A. Through testimony[64] and an exhibit,[65] DTE requests recovery of $16.88 million in total corporate membership dues, including $4.44 million in discretionary corporate membership dues, for various industry trade groups and associations, including the Edison Electric Institute (EEI) and the Electric Power Research Institute (EPRI), among others.[66]

Q. What information has the Commission required DTE Electric to provide about its corporate membership dues in past rate cases?

A. In its order in DTE Electric's general rate case, Case No. U-20836, the Commission ordered DTE Electric to "file in its future rate cases an exhibit containing an itemized list of projected costs associated with membership fees and justification for why these costs are in customers' interest."[67]

However, in the next rate case, Case No. U-21297, DTE again failed to provide the Commission with sufficient information. While the Company did provide some information about its corporate memberships in an exhibit, DAAO argued that DTE needed to provide at least "(1) the specific achievements that each organization has accomplished that are in ratepayer interests, (2) specific information about each organization's governance structure, including whether and how its leadership is directly

[64] Crozier Direct Testimony at 34–38; Davis Direct Testimony at 57–60; Guillaumin Revised Direct Testimony at 130–31.
[65] Exhibit A-27, Q1.
[66] The summation of all the requests listed in the column titled "Membership Costs" equals $16,888,624. Adding up only the discretionary memberships results in a total of $4,438,238.
[67] MPSC Case No. U-20836, Order (Nov. 18, 2022) at 308.

accountable to ratepayers, and (3) information about how each organization's interests and priorities have evolved over time."[68] In its order in that case, the Commission required the following: "DTE Electric shall provide in its next general rate case a detailed description of how these organizations *specifically* impact/benefit customers as outlined by the DAAOs, which will convey DTE Electric's roles and responsibilities in advancing ratepayer interests through its participation in each organization."[69]

Q. Has DTE Electric complied with the Commission's order in case U-21297?

A. No. While DTE Electric has provided a breakdown of its total membership dues, it has not provided a detailed description of the research, advocacy, or other programs and services provided by every organization and the costs associated with each of those activities. At best, for most organizations, it provides only vague and high-level generalities about the benefits to DTE.

First, the information that DTE provides in Exhibit A-27, Q1[70] is insufficient to meet the Commission's requirement for a "detailed description of how the organizations *specifically* impact/benefit customers…" With respect to the "Customer Benefits," for some of the memberships, DTE simply includes a link to the organization's website.[71] While these organizations may make claims on their websites about the organization's offerings, these websites are primarily geared towards companies and explain the benefits of membership to the company. In the context of seeking rate recovery, DTE has an obligation to describe the specific benefits that its memberships provide *to customers*

[68] U-21297 Order at 219–20.
[69] *Id.* at 221 (emphasis in original).
[70] *See* Exhibit A-27, Schedule Q1 (including a column labeled "Customer Benefits.")
[71] *See, e.g.*, *id.* at line 2 (CEWD), 3 (Conference Board), 8 (HCI).

which the public information on the organizations' websites falls short of doing. Even if the website provides some information, it is DTE's responsibility to explain the benefits to customers, not the responsibility of the Commission and intervenors to hunt for the information and make the argument on DTE's behalf. Other stated "Customer Benefits" include provision of information and reports to the Company,[72] but the Company does not always make clear how that information benefits customers.

Second, I am concerned that DTE Electric's approach to calculating and reporting its corporate membership expenses is not sufficiently transparent or consistent with the Commission's previous orders and guidance on this issue. DTE Electric did not provide more detailed and itemized information; it did not include a breakdown of the specific activities and benefits provided by each organization and clear explanations of the methodology used to allocate costs between recoverable and non-recoverable categories for each organization so that the Commission, intervenors, and ratepayers can understand how each of these entities' activities is appropriate and benefits ratepayers. DTE Electric removes lobbying percentages per the proportions that the organizations themselves report, which falls short of the detailed information necessary to fulfill the Commission's directive. Neither Exhibit A-27, Schedule Q1 nor any of the witness testimonies provide this level of detail about the costs associated with specific activities so that the Commission, intervenors, and ratepayers can scrutinize them.

Third, I am concerned that some of DTE Electric's requested corporate membership expenses may be used for activities that are neither directly related to the provision of utility service nor beneficial to ratepayers and may even be contrary to the

[72] *See, e.g.*, *Id.* at line 1 (ASE), 6 (Gartner).

public interest. In particular, I am concerned about DTE Electric's membership in the Edison Electric Institute (EEI), which is the largest trade association for investor-owned electric utilities in the United States and which over time has advocated for policies and positions that prioritize the financial interests of its member companies over the needs and interests of consumers and the public. As I will discuss in more detail below, EEI has taken a number of controversial and problematic positions on key energy policy issues, such as opposing the growth of distributed solar energy, supporting the rollback of federal clean air and climate regulations, and lobbying against state and local efforts to promote energy efficiency, renewable energy, and other clean energy solutions.

Fourth, the Company failed to provide any information relating to the governance structure of any of the organizations to which it pays membership dues. It does not elaborate on whether or how any of these organizations are accountable to ratepayers.

Overall, given these concerns and the lack of sufficient justification and transparency in DTE Electric's filing, I believe that the Commission should disallow recovery of a significant portion, if not all, of the company's requested corporate membership expenses in this case.

Q. Are there any particular organizations to which DTE pays membership dues with which you take particular issue?

A. Yes. I will focus my testimony on DTE Electric's request to recover approximately $1.4 million in membership dues for the Edison Electric Institute (EEI).

Q. Why are you choosing to focus on the EEI membership?

A. I am choosing to focus on DTE Electric's membership in EEI for several reasons.

First, EEI is the largest and most influential trade association for investor-owned electric utilities in the United States, with a significant budget and staff dedicated to shaping energy policy and regulation at the federal, state, and local levels. As such, EEI's activities and positions have a major impact on the direction and outcomes of the energy sector and on the costs and benefits borne by ratepayers and the public.

Second, EEI has a history of advocating for policies and positions that prioritize the financial interests of its member companies over the needs and interests of consumers and the public, often in ways that are contrary to the goals of affordability, sustainability, and equity that are critical to a just and inclusive clean energy transition.

Q. Does your focus on the Edison Electric Institute membership indicate support for the other requested corporate memberships?

A. No, my focus on DTE Electric's membership in EEI does not indicate support for the company's other requested corporate membership expenses in this case.

Without more information and documentation to support the reasonableness and prudence of these expenses and their direct relevance to the provision of utility service and the interests of ratepayers, I believe that the Commission should view all of DTE Electric's requested corporate membership expenses with skepticism and scrutiny.

However, given the limited time and resources available for this testimony and the particular significance and impact of EEI's activities and positions on energy policy and regulation, I have chosen to focus my analysis and recommendations on the

Company's EEI membership as an illustrative example of the broader concerns and issues raised by utility trade association expenses in general.

By providing a detailed examination of EEI's track record and policy agenda, and the potential impacts on ratepayers and the public interest, I hope to demonstrate the need for greater transparency, accountability, and oversight of this particular expense and these kinds of corporate membership expenses more generally and to encourage the Commission to take a more proactive and critical approach to reviewing and approving utility corporate membership requests in the future.

Q. What is the Edison Electric Institute?

A. The Edison Electric Institute (EEI) was founded in 1933 as a trade association for investor-owned electric utilities in the United States, with the mission of promoting the interests and perspectives of its member companies on a range of policy, regulatory, and technical issues affecting the electric power industry.[73]

Today, EEI represents all or almost all of the investor-owned electric utilities in the United States, which collectively serve nearly 250 million electricity customers.[74] EEI's member companies include some of the largest and most powerful utilities in the country, such as Duke Energy, Southern Company, and Exelon Corporation, as well as many smaller and regional utilities.[75]

[73] *See* Ex. DAO-11, Edison Electric Institute, About, accessed July 26, 2024, https://www.eei.org/about-eei/About.
[74] *See* Ex. DAO-12, Edison Electric Institute, U.S. Investor-Owned Electric Companies, accessed July 26, 2024, https://www.eei.org/about-eei/us-investor-owned-electric-companies
[75] *See* Ex. DAO-13, Edison Electric Institute, Member List, https://www.eei.org/-/media/Project/EEI/Documents/About/memberlist_print.pdf?la=en&hash=D5E71B7A813022B20243C1FFAD5C4170D91FFA4B.

Q. What activities does EEI undertake to shape energy regulation and policy?

A. EEI's activities and positions cover a wide range of issues affecting the electric utility industry, including but not limited to:

- Federal and state energy policies and regulations, such as the Clean Air Act, the Clean Power Plan, and renewable portfolio standards;[76]
- Grid modernization and resilience, including issues related to smart grid technologies, cybersecurity, and disaster response and recovery;[77]
- "Knowledge building regarding FERC Order 2222 (addressing Distributed Energy Resource participation in electricity markets) and its implications for utility system preparation and operation;"[78]
- Electrification and transportation, including issues related to electric vehicles, charging infrastructure, and utility involvement in transportation electrification;[79]
- Renewable energy and clean technology, including issues related to solar, wind, storage, and other emerging technologies.[80]

EEI pursues these issues through a variety of activities and channels, including:

[76] Ex. DAO-14, COMMENT FROM THE EDISON ELECTRIC INSTITUTE ON THE ENVIRONMENTAL PROTECTION AGENCY'S PROPOSED RULE NEW SOURCE PERFORMANCE STANDARDS FOR GREENHOUSE GAS EMISSIONS FROM NEW, MODIFIED, AND RECONSTRUCTED FOSSIL FUEL-FIRED ELECTRIC GENERATION UNITS; EMISSIONS GUIDELINES FOR GREENHOUSE GAS EMISSIONS FROM EXISTING FOSSIL-FUEL FIRED ELECTRIC GENERATION UNITS; AND REPEAL OF THE AFFORDABLE CLEAN ENERGY RULE, Docket No. EPA-HQ-OAR-2023-0072, (August 8, 2023) https://www.eei.org/-/media/497F22CE3B0D45619E5ABA593778C641.pdf.

[77] *See* Ex. DAO-15, Edison Electric Institute, Energy Grid, accessed July 26, 2024, https://www.eei.org/issues-and-policy/energy-grid.

[78] Crozier Direct Testimony at 38.

[79] *See* Ex. DAO-16, Edison Electric Institute, Electric Transportation, accessed July 26, 2024, https://www.eei.org/issues-and-policy/electric-transportation.

[80] *See* Ex. DAO-17, Edison Electric Institute, Clean Energy, accessed July 26, 2024, https://www.eei.org/issues-and-policy/clean-energy.

- Policy research and analysis, including the development of white papers, reports, and other technical documents on key energy issues and trends;
- Advocacy and lobbying, including direct engagement with policymakers and regulators at the federal, state, and local levels, as well as participation in regulatory proceedings and legal challenges;[81]
- Sponsorship of conferences and events of utility regulators, such as the 2024 Mid-America Regulatory Conference.[82]
- Public outreach and education, including the development of marketing and communications materials, social media campaigns, and other efforts to shape public opinion and discourse on energy issues;
- Member services and support, including the provision of technical assistance, best practice sharing, and other resources to help member companies navigate the changing energy landscape and advance their business interests.[83]

Q. What major positions has EEI taken that are contrary to ratepayer interest?

A. The Edison Electric Institute (EEI) has taken a number of positions and engaged in various activities over the years that could be seen as contrary to the interests of ratepayers and the broader public interest. Some notable examples include:

[81] Ex. DAO-18, Edison Electric Institute, 2024 Lobbying, Advocacy, and Other Expenditures (February 2024)
[82] Ex. DAO-19, Walker Orenstein, Utility regulators hosted annual conference in Minneapolis with money, STAR TRIBUNE (Jun. 18, 2024), https://www.startribune.com/walker-orenstein/11331478/.
[83] *See* Crozier Direct Testimony at 37-38.

1. Opposition to distributed solar energy and net metering: EEI has been an advocate for protecting the utility industry from the financial impacts of clean energy.[84] The keystone of this efforts has been the creation and socialization of the now-infamous "Disruptive Challenges" report, which stoked fears of the "utility death spiral" across the industry and among regulators.[85]
2. Advocacy against clean air and climate regulations: EEI has been a vocal critic of federal and state policies to reduce air pollution and greenhouse gas emissions from the electric power sector, such as their recent litigation against the EPA's implementation of the Clean Air Act.[86] EEI was found to be among one of the major fronts of climate denialism in the utility industry.[87]
3. Efforts to limit competition and customer choice: EEI has been a key resource for investor-owned utilities fighting municipalization campaigns, commissioning the "New Public Power Takeovers: Strategic Resources for Defeating Municipalization" handbook[88] and associated resources, which have guided investor-owned utilities in fighting municipalization proposals emerging from ratepayer dissatisfaction across the country.

[84] *See* Ex. DAO-20, Energy and Policy Institute, Utilities' Anti-Solar Campaign and Misinformation Debunked, accessed July 26, 2024, https://energyandpolicy.org/utilities-anti-solar-campaign-and-misinformation-debunked/.
[85] *See* Ex. DAO-21, William Pentland, Disruptive Deceptions: How Electric Utilities Stifled Rooftop Solar, Forbes (Dec. 4, 2015), https://www.forbes.com/sites/williampentland/2015/12/04/disruptive-deceptions-how-electric-utilities-stifled-rooftop-solar/.
[86] *See* Ex. DAO-22, Kim Riley, EEI takes targeted strike at EPA's power plant emissions rule, Daily Energy Insider (May 22, 2024), https://dailyenergyinsider.com/featured/43843-eei-takes-targeted-strike-at-epas-power-plant-emissions-rule/.
[87] *See* Ex. DAO-23. Emily L Williams et al., The American electric utility industry's role in promoting climate denial, doubt, and delay, 17 Environmental Research Letters 1 (2022)
[88] *See* Ex. DAO-18.

4. Support for bailouts of uneconomic coal and nuclear plants: In recent years, EEI has supported efforts to provide financial support and cost recovery for struggling coal and nuclear power plants that are facing economic challenges due to competition from cheaper natural gas and renewable energy. EEI has argued that these plants are needed for reliability and resilience, but critics have argued that the bailouts are costly, unnecessary, and contrary to market principles and clean energy goals.[89]

These are just a few examples of the ways in which EEI's advocacy and activities have been seen as contrary to the interests of ratepayers and the public by various stakeholders and observers. While EEI argues that its positions are necessary to protect utility customers and ensure reliable and affordable electricity service, critics argue that they prioritize the financial interests of utility shareholders over the needs and preferences of ratepayers and society as a whole.

These positions and activities are funded in part by utility ratepayers through the dues and other fees that utilities pay to EEI, which are then passed on to customers through rates. This has raised concerns about the transparency, accountability, and prudence of these expenses, and has led to calls for greater scrutiny and oversight of EEI's activities and costs in utility ratemaking and regulation.

The Commission should remember that the critical question in judging these activities is not only whether the positions themselves are valid, but also whether they have been undertaken in the interest of ratepayers or utility shareholders. The Commission does not need to take a position on distributed generation, municipalization,

[89] *See* Ex. DAO-24, Matt Kasper, Coal and utility interests ask for, receive, bailouts to help failing power plants, Energy and Policy Institute (Oct. 2, 2017), https://energyandpolicy.org/bailouts-for-coal-and-nuclear-plants/.

or fossil fuel facility bailouts to identify that EEI's positions on these matters have been fundamentally concerned with financial outcomes for their member companies.

Q. Why should the Commission be concerned about and scrutinize further DTE's request for reimbursement of EEI dues despite the removal of formal lobbying expenses?

A. There are several reasons why the Michigan Public Service Commission (MPSC) should be concerned about DTE Electric's EEI membership dues, even if the company has excluded a portion of these dues associated with lobbying or political activities.

First, the distinction between lobbying and non-lobbying activities is often blurry and subjective and may not fully capture the scope and influence of EEI's advocacy and outreach efforts. EEI engages in a wide range of activities that could be seen as indirect or grassroots lobbying, such as public education campaigns, policy research and analysis, and stakeholder engagement and mobilization, which may not be formally reported as lobbying expenses but still have the effect of shaping public opinion and policy outcomes in ways that benefit utility interests.

The best expression of this concern is found in the rebuttal testimony of Xcel Energy in its most recent gas rate case. Responding to testimony from Dr. Karlee Weinmann of the Energy and Policy Institute, who argued for a more expansive understanding of lobbying, Xcel stated that "there is no practical way for the Company to review each activity and make a determination as to whether it constitutes lobbying."[90] Xcel finds itself accidentally hitting the nail on the head: Institutions like the American

[90] Ex. DAO-25, *In re Xcel Energy Inc.*, Minnesota Public Utilities Commission Docket Nos. G002/GR-23-413, Bhosale Rebuttal Testimony (May 29, 2024) at 9.

Gas Association (which was the subject of that testimony) and EEI conduct a broad array of activities that are clearly intended to shape regulatory and legislative action while steering clear of the IRS definition of lobbying. The vast scope makes it difficult for the companies themselves, let alone their regulators or legislators, to understand and be able to explain what is actually going on. It is notable that in a settlement agreement filed on June 26th, 2024, Xcel agreed to remove all its membership dues from recovery.[91]

The Commission should also be concerned about its own conflicts of interest. The Edison Electric Institute is a regular sponsor of regulatory events, including the 2024 Mid-America Regulatory Conference. MARC does not allow entities directly regulated by the attending officials, such as DTE Energy to sponsor the conference, but it does allow industry associations to do so. In response to a discovery request, DTE stated that it has no information about how their dues are allocated to EEI's different activities, has no part in decision-making about sponsorships, and has no way to verify that its membership dues do not fund sponsorships for events and conferences which the Commission attends.[92] Thus, the Commission and its staff are presumably attending conferences which are, within a single degree of separation, funded by the utilities they regulate with money recovered from ratepayers at the Commission's approval.

[91] Ex. DAO-26, *In re Xcel Energy Inc.*, Minnesota Public Utilities Commission Docket Nos. G002/GR-23-413, Settlement Agreement (June 26, 2024) at 11-12.
[92] Ex. DAO-27, DAAODE-3.13b and DAAODE-3.14ai.

Q. Does DTE Electric convincingly demonstrate that the membership in EEI is advancing ratepayer interests?

A. No, based on my review of DTE Electric's testimony and exhibits in this case, the company does not convincingly demonstrate that its membership in EEI is advancing the interests of ratepayers or providing clear and tangible benefits to customers.

As discussed in my previous responses, EEI has a long history of advocating for policies and positions that prioritize the financial interests of its member utilities over the needs and preferences of ratepayers and the broader public interest, such as opposing renewable energy and energy efficiency programs, fighting against air quality and climate regulations, and supporting bailouts of uneconomic fossil fuel plants.

While DTE Electric claims that its EEI membership provides benefits to ratepayers such as access to research and information on industry trends, best practices, and regulatory issues,[93] the Company does not provide any specific examples or quantitative evidence of how these benefits have actually translated into improved service quality, reliability, affordability, or other tangible outcomes for customers. DTE Electric states that the value of the Company's membership to ratepayers are "embedded in each business unit's historical and projected data in an implicit, rather than explicit manner"[94] and merely references Exhibit A-27, Schedule Q1—the deficiencies of which I have already addressed—in answer to the discovery requesting a clear description of ratepayer benefits.

While certain elements of the value DTE claims arises from their EEI membership, such as mutual assistance coordination, are plausibly beneficial to

[93] Crozier Direct Testimony at 36–37.
[94] *See* Ex. DAO-28, DAAODE-3.15ai.

ratepayers, without any means to discern the proportion of membership dues that go to those elements, the Commission has no manner in which to assess an appropriate portion of dues to approve or reject.

Overall, while DTE Electric claims that its EEI membership is providing value to ratepayers, the evidence suggests that a significant portion of these dues are going towards activities that are primarily aimed at advancing utility industry interests, rather than delivering tangible benefits to customers.

As such, I do not believe that DTE Electric has met its burden of demonstrating that its EEI membership is a reasonable, prudent, or necessary expense for ratepayers to bear, or that it is consistent with the public interest and the goals of a fair and equitable regulatory process.

The MPSC should carefully scrutinize these costs and require DTE Electric to provide more specific and quantitative evidence of the direct ratepayer benefits of its EEI membership, if any, and to justify why these benefits outweigh the potential harms and risks to customers and the broader public interest.

Q. What should the Commission do in the instant case?

A. Based on the concerns and issues raised in my testimony regarding DTE Electric's EEI membership and other corporate political spending, I recommend that the Michigan Public Service Commission (MPSC) take the following actions in this rate case:

1. Disallow DTE Electric’s entire $1.4 million request for recovery of EEI membership dues from ratepayers on the grounds that these costs are not reasonable, prudent, or

necessary for the provision of safe and reliable utility service and are not consistent with the public interest and the goals of a fair and equitable regulatory process.

2. Examine closely the Company's justification for its other membership requests and reject those that have similar failings as pointed out above for EEI, e.g., lack of detail about what specific activities are funded at what levels with DTE's contributions and lack any specific examples or quantitative evidence of how these benefits have actually translated into improved service quality, reliability, affordability, or other tangible outcomes for customers.
3. Make explicit in its order that failure to meet the requirements to demonstrate explicit ratepayer benefit identified in case 21297 for any discretionary corporate membership will result in the rejection of cost recovery.

Q: Please summarize your recommendations for the Commission in this case.

A: Based on my analysis of the deficiencies in DTE Electric's rate case proposal, I recommend that the Commission take the following actions:

- **Affordability**
  - Require that DTE Electric adopt and uniformly and accurately use the Commission's approved definition of affordability;
  - Order that DTE Electric set goals to reduce energy burden and report on their achievement;
  - Require DTE Electric to present a comprehensive assessment of the affordability impact of its proposed rates and investments in future rate case filings. This assessment should include a detailed analysis of affordability gaps and disparities

across different customer groups and geographic areas, as well as specific proposals for how to mitigate these impacts and support more equitable outcomes.

- Order DTE Electric to propose in its next rate case a universal affordability program by adding to its revenue requirement an operating expense equal to the projection of the annual affordability gap while shall be utilized to reduce arrears and bills such that no DTE Electric customer is being charged in excess of 3% of annual income according to the program parameters outlined in my testimony.

- **Outage Credits**
  - Reject DTE Electric's proposal for deferred accounting treatment of outage credits;
  - Reject DTE Electric's proposed system for limiting their fiscal liability for the cost of outage credits;
  - Reconsider the establishment of hourly, automatic, progressive outage credits for all customers.
- **IT Capital**
  - Reject DTE Elecrtic's recovery of $10.7 million of IT Capital Investment in the Collections Digital Self-Service Platform, as well as any other proposed IT investments that are primarily focused on collections automation and efficiency rather than customer assistance and affordability;
  - Require DTE Electric to provide a more detailed and comprehensive cost-benefit analysis of its IT investments, including specific metrics and targets for reducing energy burdens, preventing disconnections, and improving customer satisfaction and affordability, particularly for low-income and vulnerable households.

- **TOU Rates**
  - Find that DTE Electric's TOU study does not meet the standards of the Commission's order in Case No. U-21297;
  - Reject DTE Electric's request to retire the D1.6 flat rate for low-income customers and to transition all customers to the D1.11 TOU rate at this time;
  - Require DTE Electric to conduct a more comprehensive and collaborative study of the potential impacts and opportunities of TOU rates for low-income customers, in line with the Commission's order in Case No. U-21297.
- **Infrastructure Equity**
  - Reject or substantially reduce DTE's proposed capital spending on the CODI program, particularly in the Core Area which demonstrates higher-than-average reliability;
  - Require DTE to analyze changes in demographics over time when assessing the equity impacts of its proposed long-term investments;
  - Require DTE Electric to use regression analysis to have a complete understanding of equity outcomes along lines of race and class.
- **Corporate Memberships**
  - Reject DTE Electric's entire $1.4 million request for recovery of EEI membership dues from ratepayers;
  - Make explicit in its order that failure to meet the requirements to demonstrate explicit ratepayer benefit as identified in Case No. U-21297 for any discretionary corporate membership will result in the rejection of cost-recovery.

Q: Does this conclude your Direct 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 ALJ Sally L. Wallace

REBUTTAL TESTIMONY OF JACKSON KOEPPEL

ON BEHALF OF

DETROIT AREA ADVOCACY ORGANIZATIONS

(SOULARDARITY AND WE WANT GREEN, TOO)

August 16, 2024

Q: Please state your name, occupation, and business address.

A: My name is Jackson Koeppel. I am an independent consultant, primarily focused on working on energy regulatory issues for Soulardarity and We Want Green, Too. My business address is 189 Monterey St, Highland Park, MI 48203.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Soulardarity and We Want Green, Too—collectively, the Detroit Area Advocacy Organizations (DAAO).

Q: Are you the same Jackson Koeppel who provided direct testimony in this case?

A: Yes.

Q: Have your background or qualifications changed since then?

A: No.

Q: What is the purpose of your rebuttal testimony?

A: I rebut the following witnesses in part with respect to the following topics:

- Attorney General Witness Coppola and ABATE Witness Walters regarding their proposed Return on Equity (ROE);
- CEO Witnesses Volkman and Kenworthy with regard to DTE Electric's incorporation of environmental justice considerations into their Global Prioritization Model (GPM);
- Attorney General Witnesses Alvarez and Stephens regarding their recommendations for a cost-benefit analysis of DTE's capital spending.

Q: Are you sponsoring any exhibits?

A: Yes, I am sponsoring the following exhibit:

DAO-29. U.S. EPA, *EJ Screen: Environmental Justice Screening and Mapping Tool, How to Interpret EJ Screen Data*

Return On Equity

Q: What positions did other intervenors take on DTE Electric's proposed return on equity?

A: Attorney General Witness Coppola recommends the Commission adopt an ROE of 9.85%[1] and found that "the 9.9% ROE granted to DTEE in 2023 and similarly granted to other utilities in Michigan are outlier ROE rates considerably higher than the equity returns granted by state regulatory agencies for most other electric utilities."[2] Witness Coppola found that DTE Electric's cost of capital is 9.18%,[3] but arrived at the recommended 9.85% ROE in the DCF approach by weighting the three models he ran and then adding 5 basis points of "cushion" to arrive at 9.85%.[4] Witness Coppola argues this would save customers $6.4 million annually relative to the 9.9% ROE.[5]

City of Ann Arbor Witness Stults recommends reducing ROE to send a message to DTE Electric that failure to improve reliability performance will impact their rate of profit.[6] Witness Stults highlights that DTE has above-average prices and poor reliability,

[1] Direct Testimony of Sebastian Coppola, MPSC Case No. U-21534 at 74, lines 5-6.
[2] *Id*. at 94, lines 9-11.
[3] *Id*. at 99, lines 9-11.
[4] *Id*. at 99, lines 13-16.
[5] *Id*. at 100, lines 7-8.
[6] Direct Testimony of Melissa Stults, MPSC Case No. U-21534 at 13, lines 16-19.

which should impact the Commission's consideration of their ROE.[7] Witness Stults further points out that the arguments of Witness Villadsen in previous cases claimed that a failure to increase ROE would impact DTE Electric's ability to attract equity investors, but that the Commission's decision to reject those requests has not prevented DTE from delivering "premium" returns to shareholders.[8]

ABATE Witness Walters found a reasonable ROE range of 9.2% to 10% and recommends an ROE of 9.6% at the midpoint of the range.[9]

Walmart Witness Perry noted that the average of the authorized ROES to IOUs in 2021, 2022, 2023, and so far in 2024 is 9.51%, and the median is 9.5%.[10] Witness Perry also notes that an ROE of 9.62% would reduce the revenue requirement by $103.2 million.[11]

Q: Do you agree with the testimony of these witnesses that DTE's requested ROE is too high?

A: Yes. I find that these witnesses have accurately and robustly defended the position that DTE Electric's current ROE is higher than industry standards, and that the requested increase would be even more so, that DTE Electric overstates their business risks, and that DTE Electric's higher-than-average ROE contributes to their failure to improve performance.

[7] *Id*. at 8-9.
[8] *See id*. at 13, lines 7-12.
[9] Direct Testimony of Christopher C. Walters, MPSC Case No. U-21534 at 3, lines 2-7.
[10] Direct Testimony of Lisa V. Perry, MPSC Case No. U-21534 at 12-13.
[11] *Id*. at 15, lines 12-14.

Q: Do you agree with the proposals of Attorney General Witness Coppola and ABATE Witness Walters?

A: No. While I find that Witnesses Coppola and Walters' proposals are thoughtful, they ultimately fail to fully address the overcharging of ratepayers for shareholder benefit. Both Walters and Coppola run numerous models to estimate ROE and take the average. Coppola takes the further step of providing 5 basis points of "cushion."[12] While either a 9.85% or 9.6% ROE would be a substantial improvement, they both fall short of setting an ROE that appropriately reflects DTE Electric's true cost of capital, appropriately incentivizes DTE to improve service, and protects ratepayers from unjust and unnecessary cost increases.

Q: What do you recommend regarding the Company's proposed ROE increase?

A: I recommend that the Commission adopt an ROE of 9.18%, the actual cost of capital identified by Witness Coppola's DCF analysis.[13] Adopting a reduction of this scale would be a tremendous step towards correcting the historic imbalance of shareholder and ratepayer interests and would signal to DTE that they will no longer be allowed to profit without regard for their performance. Further, it will make an immediate and long-term impact on the affordability crisis. As the Commission navigates the need for expanding capital investment to reconstruct the electric distribution system, a lower ROE associated with the cost of capital is essential to ease the tension between affordability and infrastructure investment. To take a very high-level example, DTE Electric has indicated that they need to invest over $20 billion in the modernization of the 4.8kV distribution

[12] Coppola Direct Testimony at 99, lines 15-16.
[13] *Id*. at 99, lines 9-11.

grid.[14] Every basis point of reduced ROE earned on those capital investments saves ratepayers millions of dollars.[15] The Commission simply has no other tool nearly as effective to durably reduce the cost impact of investment and the scale of the affordability crisis.

Equity in the Global Prioritization Model

Q: What do CEO Witnesses Volkman and Kenworthy state about DTE Electric's integration of EJ and Equity into their Global Prioritization Model?

A: Witness Volkman notes that DTE Electric added the "Investment in EJ communities" impact dimension in the GPM.[16] Witness Volkman generally agrees with this approach, while asking for more information and technical conferences on the GPM.[17]

Witness Kenworthy notes that DTE utilized the MiEJScreen tool to identify vulnerable communities, which it defined as any census tract above the 80th percentile threshold of MiEJ composite score, "consistent with the U.S. EPA's approach."[18] Witness Kenworthy makes numerous recommendations to improve the utilization of EJ analysis including detailed plans for vulnerable communities, more transparency, more engagement, tracking the impact of EJ metrics on GPM scores, measuring reliability

[14] *See 2023 Distribution Grid Plan*, DTE Electric Company, MPSC Case No. U-20147 (September 29, 2023) at 119 ("The investment needed to completely convert the 4.8kV system to a higher voltage is estimated at $20-25 billion in 2023 dollars[.]")
[15] Even 0.01% of $20 billion is $2 million.
[16] Direct Testimony of Curt Volkman, MPSC Case No. U-21534 at 7, lines 17-19.
[17] *Id*. at 8-9.
[18] Direct Testimony of William D. Kenworthy, MPSC Case No. U-21534 at 18, lines 9-12.

progress and grid access in EJ communities, and advanced mapping tools as well as adopting the use of regression analysis.[19]

Q: Do you agree with CEO Witness Volkman's recommendation regarding the Company's application of its GPM as it relates to its consideration of Environmental Justice?

A: No. While Witness Volkman does not applaud DTE's approach exactly, the implication of his limited recommendations is that DTE has made progress and needs to keep engaging to improve. I think this gives DTE far too much credit. As I discussed in initial testimony and as I discuss further below, DTE Electric's reliance on a binary definition of "vulnerable communities" as any that are above the 80th percentile of MiEJ score is inadequate. While I am not opposed to more transparency and engagement, I do not believe they will be effective without acknowledging that DTE Electric continues to do the bare minimum in this regard and needs to be compelled to go further faster.

Q: Do you agree with Witness Kenworthy's statement that DTE Electric's adoption of an 80th percentile threshold definition for vulnerable communities based on MiEJScreen composite score is consistent with U.S. EPA's approach?

A: No. U.S. EPA specifically states that "the 80th percentile filter in EJScreen is not intended to designate an area as an 'EJ community.'"[20] Instead, "EPA identified the 80th percentile filter as that initial starting point[,]"[21] and recommends that additional analysis

[19] *Id*. at 18-21.
[20] Ex. DAO-29. U.S. EPA, *EJ Screen: Environmental Justice Screening and Mapping Tool, How to Interpret EJ Screen Data*, at 4.
[21] *Id*.

be performed before "making any decisions about potential environmental justice issues."[22] In other words, "EJScreen provides screening level indicators, not a determination of the existence or absence of EJ concerns."[23]

As I discussed in my direct testimony, the 80th percentile is both overinclusive and underinclusive. I also discuss in direct testimony how DTE's core rationale in defense of the CODI program, which invests in targeted communities in Detroit that are experiencing economic development and load growth, as well as demographic shifts towards being higher income and more proportionally white, is unrelated to EJ measures but that these investments nonetheless are counted as investments in EJ communities in DTE's simplistic analysis.[24]

Q: What are your recommendations on better integrating equity into the GPM?

A: First, the Commission should find that DTE's current approach fails to meaningfully improve equity outcomes or planning processes. Second, the Commission should require that DTE Electric move beyond the simplistic 80th percentile threshold as its proof of equity performance and should specifically be required to consider demographic changes over time in determining the equity of their investments, particularly in cases like the CODI program where the justification for investment is population increase and developments which contribute to gentrification. Finally, the Commission should adopt

[22] *Id*.
[23] *Id*.
[24] Direct Testimony of Jackson Koeppel, MPSC Case No. U-21534 at 41-43.

the recommendations made by Witness Kenworthy as baselines (rather than aspirations) for achieving equity in grid planning.

Equitable Grid Modernization and Cost-Benefit Analysis

Q: Please summarize the positions of Attorney General Witnesses Alvarez and Stephens on capital spending and cost-benefit analysis.

A: Witness Alvarez demonstrates that DTE Electric has a capital bias, which he argues can only be restrained by regulators.[25] Witness Stephens argues that capital spending is not causing reliability improvements.[26] This reinforces the position of Witness Alvarez that the Commission should not rely on the GPM, which he argues is based on "subjective GPM user assessments."[27] Both Witness Alvarez and Witness Stephens argue that the Company should provide more cost-benefit analysis of spending.[28] Witness Alvarez and Witness Stephens also make several specific recommendations to the Commission on capital spending, including the rejection of the extension and expansion of IRM,[29] the rejection of capitalization of vegetation management,[30] and the rejection $405.566 million in 2024 and test year spending on a range of capital investment proposals.[31]

[25] Direct Testimony of Paul J. Alvarez, MPSC Case No. U-21534 at 25, lines 2-6.
[26] Direct Testimony of Dennis Stephens, MPSC Case No. U-21534 at 45, lines 15-17.
[27] Alvarez Direct Testimony at 46, lines 1-3.
[28] *See id*. at 64 lines 3-4 (recommending that recovery of certain costs be disallowed because the Company failed to develop a "benefit-cost" analysis, among other reasons); Stephens Direct Testimony at 45, lines 1-3 ("The Company has not provided cost-benefit analyses to support these investments.")
[29] Alvarez Direct testimony at 8, line 12.
[30] *Id*. at 8, lines 13-15.
[31] Stephens Direct Testimony at 46-47.

Q: Do you agree with Witnesses Alvarez and Stephens that the Commission should increase governance over DTE's capital spending?

A: Yes. I find Witness Alvarez's argument that DTE Electric's proposals "accrue to shareholders' benefit and increase risks for customers"[32] convincing. I agree with Witness Alvarez's assessment of DTE's capital bias, the responsibility of the Commission to address it, and the argument that DTE's distribution investments have historically failed to deliver reliability as DTE projects.[33] While it is not in the purview of my testimony to review the proposed revenue requirement reductions in detail, I am inclined to the view that DTE's proposals are excessive and unjustified.

Q: Do you believe that Witnesses Alvarez and Stephens' recommendations for additional cost-benefit analysis would resolve the Company's issues with capital spending?

A: No. Despite my broad alignment with their arguments, I am concerned that the approach of focusing heavily on cost-benefit justifications will ultimately fail to address equity. Energy affordability is already at crisis levels, as discussed in my direct testimony and the direct testimony of DAAO Witness Justin Schott.[34] The most durable and cost-effective solutions to affordability are investments into the homes of those suffering from it, as discussed by Witness Kinkhabwala.[35] Implementation at-scale of the affordability solutions outlined by Witness Kinkhabwala, however, rely upon modernized grids in LMI communities with the hosting capacity for distributed generation and

[32] Alvarez Direct Testimony at 10, lines 7-8.
[33] Alvarez Direct Testimony at 17, lines 1-5.
[34] Direct Testimony of Justin Schott, MPSC Case No. U-21534 at 7-8.
[35] *See* Direct Testimony of Yunus Kinkhabwala, MPSC Case No. U-21534 at 19-28.

electrification.[36] This is especially true as electrification and reduced reliance on the gas distribution system advances. As discussed in the Just and Equitable Energy Transition framework I introduce in my direct testimony,[37] adopting a zero-sum relationship between grid transformation and affordability will continue to inscribe inequities in the current system. I believe that the rigorous cost-benefit analyses requested by Witness Alvarez and Witness Stephens have tremendous value, but are not adequate to the task of a just and equitable energy transition without a broader strategic assessment of how frontline communities will be ensured equal access to the benefits of energy transition.

Q: What recommendations do you make of the Commission?

A: I make the following recommendations to the Commission:

- Adopt a finding that DTE's capital spending is self-interested and not generating the purported benefits for ratepayers;
- Adopt DAAO's recommendation for a universal affordability program to ensure rate affordability through the energy transition;
- Adopt the recommendation for greater cost-benefit analysis requirements as an interim measure to protect against capital spending; and
- Acknowledge that the complete modernization of the electric system is an essential goal and order DTE Electric, in an integrated analysis with DTE Gas, to conduct an analysis of how that will be possible while addressing the affordability crisis.

[36] *Id*. at 31-32.
[37] *See* Koeppel Direct Testimony at 17-18.

Q: Does this conclude your rebuttal testimony?

A. Yes.