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May 19, 2022

VIA ELECTRONIC CASE FILING

Ms. Lisa Felice, Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Highway
Lansing, MI 48917

Re: **MPSC Case No. U-20836**: 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.

Dear Executive Secretary:

Enclosed for filing please find the ***City of Ann Arbor's Direct Testimony*** for the above referenced case.

Should you have any questions or comments regarding this matter, please do not hesitate to contact my office.

Sincerely,

Valerie J.M. Brader

Counsel to the Michigan Municipal Association
for Utility Issues and The City of Ann Arbor

cc: w/enclosure: Parties of Record

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-20836 ALJ Sharon L. Feldman

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PROOF OF SERVICE

On the date below, an electronic copy of **the City of Ann Arbor's Direct Testimony** was served on the following:

Name/Party	E-mail Address
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The statements above are true to the best of my knowledge, information and belief.

Dated: May 19, 2022

RIVENOAK LAW GROUP P.C.

By: Valerie J.M. Brader

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STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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DIRECT TESTIMONY OF TIFFANY GIACOBAZZI

ON BEHALF OF

THE CITY OF ANN ARBOR

May 19, 2022

I. INTRODUCTION & QUALIFICATIONS

Q. Please state for the record your name, position, and business address.

A. My name is Tiffany Giacobazzi. I am the Urban Forestry & Natural Resources Planning Coordinator for the City of Ann Arbor. My office is located at 4251 Stone School Road, Ann Arbor, MI 48108.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of the City of Ann Arbor.

Q. What is your profession?

A. I am an ISA Certified Arborist.

Q. Please summarize your experience as an ISA Certified Arborist.

A. I have been an ISA Certified Arborist for 13 years and an ISA Tree Risk Assessment Qualified Arborist for 8 years. I have managed two state urban forestry programs (South Dakota and Indiana) and two municipal programs (Novi and Ann Arbor). I was also President of ISA Michigan, the Michigan Chapter of ISA, during 2021.

Q. In your professional role, do you interact with DTE?

A. Yes.

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

A. No.

Q. What is the purpose of your testimony?

A. To bring forward the correlation between routine tree trimming and reduction in storm damage.

II. REGULAR TREE TRIMMING REDUCES RISK OF DAMAGES TO CRITICAL INFRASTRUCTURE

Q. What is the usual effect of tree trimming on the health of a tree?

A. Proper trimming improves tree health by eliminating dead or dying branches, crossing or rubbing branches, and weak branch unions.

Q. Do you find that there are fewer fallen branches for trees that have been trimmed recently?

A. Yes. Trees that have been trimmed have had weakly attached, damaged, or dead branches removed.

Q. In your experience, would trees that are not regularly trimmed lead to falling branches?

A. Yes. Trees that are not pruned routinely, unhealthy habits, such as rubbing and crossing branches aren't removed, leading to increased likelihood of failure of those branches. Dead and diseased limbs not removed, can lead to decay and spread of disease, ultimately killing the tree. All these issues increase the overall risk the tree poses to potential targets (people, vehicles, and critical infrastructure).

Q. In your experience, what types of problems might arise from falling branches?

A. The greatest problem would be injury or death of someone near the tree at the time of failure. Second would be damage to critical infrastructure, like power lines, or blocking

main roadways, that people rely on. Third would be damage to property, like vehicles, homes, picnic tables, etc.

Q. What would you recommend the Commission do about the problems you have described?

A. First, the Commission should require any funding provided to utilities to be spent on pruning when it's provided to them. Maintaining a routine pruning cycle should show a reduction in tree and limb failures, which would expectedly lead to a reduction in outages of pruned areas.

Q. Does that conclude your 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

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DIRECT TESTIMONY OF MATTHEW GROCOFF

ON BEHALF OF

THE CITY OF ANN ARBOR

May 19, 2022

I. INTRODUCTION & QUALIFICATIONS

Q. Please state for the record your name, position, and business address.

A. My name is Matthew Grocoff. I am the founder and principal at THRIVE Collaborative, LLC, ("THRIVE") which is located at 122 S Main St, Ann Arbor, MI 48104 and 6200 2nd Ave, Detroit, MI 48202.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of the City of Ann Arbor, which is a member of the Michigan Municipal Association for Utility Issues.

Q. Please describe your employer.

A. THRIVE is an Ann Arbor and Detroit based real estate development, design, building, and consulting firm dedicated to creating the life enhancing communities and cities needed for the 22nd Century. Our mission is to accelerate the shift towards beautiful, healthy, and environmentally responsive design and lead the transformation to a truly sustainable human-built environment that is socially just, nature rich and ecologically restorative. Among its major efforts right now is the development of Veridian at County Farm ("Veridian"), a unique collaboration between THRIVE and Avalon Housing, a non-profit 501(c)(3) whose mission is to build healthy, safe, and inclusive supportive housing communities as a long-term solution to homelessness.

Q. In your professional role, do you interact with potential homeowners who are customers of DTE?

A. Yes. As THRIVE is working to develop Veridian, which is planned as a mixed-income development with 100% electrified (no gas) homes with integrated solar and battery storage, 93 EV chargers, and targeting net zero energy, my role includes interacting with DTE regarding that development. In my role, I regularly interact with potential homeowners who have an interest in sustainability and decarbonization and discuss issues of their energy and other utility usage with them.

Q. In your professional role, do you interact with DTE?

A. Yes. As THRIVE is working to develop Veridian, which is planned as a mixed-income development with 100% electrified (no gas) homes with integrated solar and battery storage, 93 EV chargers, and targeting net zero energy, my role includes interacting with DTE regarding that development.

Q. What is your educational background?

A. Juris Doctor; University of Georgia, Henry Joseph Lumpkin, College of Law, and my BS in Psychology from the University of Georgia.

Q. What is your professional background?

A. I've worked for 15 years as a principal of THRIVE working to build net zero energy buildings and communities, and as an international advocate for sustainable energy and water systems.

Q. Is your testimony today as a lay or as an expert witness?

A. My testimony is based on my first-hand experiences in my day-to-day work at THRIVE, and the opinions I formed as a result. While I do have expertise in energy issues, all of the observations in this testimony are based on my personal knowledge.

Q. What is the purpose of your testimony?

A. I want to discuss what developers and homeowners that are on the leading edge of sustainability are looking for in utility programs, and how DTE's proposed offerings, including but not limited to the new distributed generation tariffs and the battery pilot program, do or don't meet those needs.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit AA-1: Order in State of Vermont Public Utility Commission Case No. 19-3167-TF entered May 20, 2020

II. DTE'S NON-WIRES ALTERNATIVE: VERIDIAN

Q. Are you aware that DTE is seeking approval for funding for a non-wires alternative associated with Veridian?

A. Yes. I learned that the DTE filed the request when I was contacted by representatives of the Michigan Public Service Commission Staff. However, on behalf of the THRIVE Collaborative, I've been working with DTE since January 2020 to pilot a program at Veridian at County Farm in Ann Arbor. As an all-electric neighborhood, with 93+ EV chargers, 1.3MW solar + battery, and no gas infrastructure, I believe Veridian presents a

once in a decade opportunity to find grid-optimized onsite renewable energy at the neighborhood scale.

Q. What can you tell us about the status of those efforts?

A. DTE requested that I sign a confidentiality agreement regarding our discussions related to Veridian's interconnection, and I did so. As a result, I can tell you very little, except that at this time THRIVE and DTE have no agreements regarding how to move forward with Veridian's interconnection and energy plans, or potential areas of collaboration.

III. DTE'S PROPOSED BATTERY PILOT PROGRAM

Q. Are you aware of DTE's proposed battery pilot program?

A. Yes.

Q. Do you believe it would be attractive to customers?

A. No. Unlike other programs in the nation, DTE's program does not appear to have much benefit to customers. While customers value resiliency, I believe customers would not be willing to pay for "resiliency as a service" that they could only benefit from during a power outage. For example, the Green Mountain Power program in Vermont, similarly charges $50 per month. However, GMP customers are able to receive battery energy credits which generally offsets the monthly fee, while still giving resiliency benefits. Some customers may receive a net positive monthly credit. *See* Exhibit AA-1.

Q. Please explain why customers who are willing to make large dollar investments in sustainability would not be interested in participating in a similar program.

A. At Veridian at County Farm, most homes will come standard with a battery backup system included in home price, with an option to purchase more. The incremental monthly mortgage cost for battery + solar has value for our customers. Homebuyers know they could use the energy they produce rather than sending it back to the grid at lower return rates. However, it is very difficult, if not impossible, to quantify what the dollar value will be for this investment. Detailed energy use data is not available to DTE customers to effectively optimize Time of Use and Demand Response rates. These programs could benefit customers financially and help ease stress on the grid during peak hours. Veridian homeowners will not receive credits for storing solar energy nor provide grid optimization. DTE also pays customers a lower rate for solar that is sent to the grid when batteries are full. Even the most sophisticated energy user would have no way to understand or optimize the benefit. In my own home, I have 8.1kW solar + two 26kW of battery storage. However, without my data, it is difficult for me, an expert in the field, to understand or quantify our personal benefit or how to optimize grid benefit. Data portability, the ability for a customer to access and share their energy data with third parties, would help customers assess the value of owning their own batteries as well as the value it provides to the utilities and the grid.

Q. As part of developing Veridian, did you look at "bring your own device" storage options offered by other utilities to help educate yourself on possible value structures?

A. Yes. I've had conversations directly with Green Mountain Power, Rocky Mountain Power, Sonnenbatterie and others in the industry. Programs like Rocky Mountain Power's Wattsmart Battery Program offer customers an upfront incentive, plus ongoing bill credits,

and available federal tax credits. While programs like these, Veridian homeowners would be able to receive credits from the utility for their investments, maintain the resiliency they desire, as well as help make their energy investment grid beneficial rather than simply a private benefit to themselves. I believe if this were available to Veridian customers, we would have a greater interest in options for additional batteries.

Q. Is DTE's proposed battery pilot program an attractive program? Why or why not?

A. Unfortunately, no. DTE's program is essentially a "Resiliency Fee" program. Similar programs cost between $2 to $6 per month. DTE's $50 per month makes very little sense as a Resiliency Only Fee. DTE has not provided modeling to support that the battery pilot program would benefit participating customers in their first year. Veridian is designed with homes ranging from $200,000 to $950,000. $50 per month would have a greater impact on cost of ownership for owners of the lower cost homes. Without bill credits similar to other programs, I do not believe backup power alone is sufficient motivation for buyers to consider adding $50/month to living expenses. Customers expect reliable power. It is not something for which they are willing to pay "a premium."

Q. Are proposed battery pilot programs without a bring-your-own-device option likely to be attractive to sustainability-focused consumers?

A. I don't believe so. Veridian customers have told us that they value the ability to have their own batteries + solar. At Veridian, homebuyers can have batteries from day one of ownership. Thus, they are able to finance Powerwalls through their mortgage at little additional monthly cost, as well as receive any available Federal Tax Credit. Existing

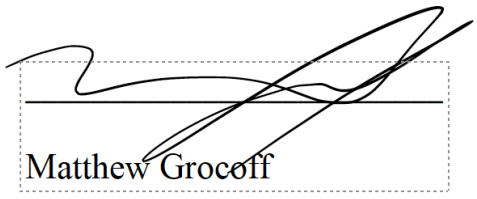
homeowners can finance batteries through programs like Michigan Saves and also benefit from available tax credits. Further, new EVs have the ability to supply the home and discharge to the grid, allowing homeowners to include backup power with the purchase and financing of their vehicle. A bring-your-own-device program, like the one in the Green Mountain Power Program, addresses concerns that the utility is picking winners and losers in behind-the-meter technology manufacturers.

Q. What other features of the Green Mountain Power Program are more attractive than DTE's proposed battery pilot program?

A. The large spread of residential TOU rates in the Green Mountain Power Program gives real choice to battery owners to use the battery to manage their own load to reap savings or let the utility do so.

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.



STATE OF MICHIGAN

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DIRECT TESTIMONY OF DR. MELISSA STULTS

ON BEHALF OF

THE CITY OF ANN ARBOR

May 19, 2022

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Dr. Missy Stults and I am the Sustainability and Innovations Director for the City of Ann Arbor. My business address is 301 E. Huron Street, Ann Arbor, Michigan, 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 a Bachelor's degree in Marine Biology and Environmental Sciences from the University of New England.

Professionally, I have spent the last 17 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, state-wide) and sectors (i.e., built, natural, social, cultural, economic). I have been the City of Ann Arbor's head of Sustainability and Innovations for just under four 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, Michigan ("Ann Arbor" or "City").

Q. Have you previously testified before this Commission or as an expert in other proceedings?

A. Yes. I provided testimony in U-20471.

Q. Have you reviewed DTE's Rate Case U-20836 Filing?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to share the City of Ann Arbor's concerns related to three primary areas/activities proposed by DTE Electric Company (DTEE) in U-20836, as outlined below:

- **Utility's Failure to Integrate Well Known Climate Variables into Utility Decision Making and Designed Programs**. Specifically, the failure to integrate climate projections into decision-making despite the recognition that climate change is impacting operations, increasing costs, and negatively impacting reliability.
- **Insufficient Focus on Reliability Enhancing Activities.** Multiple witnesses emphasize the importance of reliability and yet the solutions identified in the rate case fall far short of what is necessary to enhance electric reliability for consumers and some proposed activities negatively impact reliability.
- **Anti-Competitive D1.12 Rate Structure and Requirement to Take Rate for**

Distributed Solar Customers that Effectively Functions as an Exit Fee. My analysis of the Company's testimony shows that the D1.12 rate is trying to impose a fee on people that are self-supplying. The lack of choice for solar customers, but the option of a choice for all other customers indicates that this is a clear fee that is only being applied to those rate payers that have installed distributed solar systems. In my assessment, this is an exit fee.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit AA-2	Dr. Melissa Stults CV
Exhibit AA-3	U.S. Energy Information Administration webpage
Exhibit AA-4	Department of Energy: Climate Change webpage
Exhibit AA-5	Climate.gov blog post
Exhibit AA-6	Fourth National Climate Assessment (2018)
Exhibit AA-7	Natural Living Fall/Winter 2018
Exhibit AA-8	MLive Article: Sewage spills into Saline River
Exhibit AA-9	MLive Article: Power outage
Exhibit AA-10	ConEdison Climate Change Resiliency Plan
Exhibit AA-11	PSEG Sustainability and Climate Report
Exhibit AA-12	California Public Utilities Commission Order
Exhibit AA-13	MLive Article: Ann Arbor declares climate emergency
Exhibit AA-14	Great Lakes Integrated Sciences and Assessment webpage
Exhibit AA-15	GLISA: Future Climate Scenarios

Exhibit AA-16	DOE: Solar and Resilience Basics
Exhibit AA-17	Green Mountain Power: Tesla Powerwall
Exhibit AA-18	NARUC Report
Exhibit AA-19	Hawaii Public Utilities Commission Order
Exhibit AA-20	Hawaiian Electric News Release
Exhibit AA-21	MLive Article: $20M power grid upgrade

II. DTE'S FAILURE TO USE KNOWLEDGE REGARDING CLIMATE CHANGE IN BUSINESS PLANNING

Q. Do you believe the utility has effectively integrated scientific knowledge about climate change into their decision making?

A. No. Science shows that climate change and extreme weather events such as flooding, high winds, heat waves, ice storms, wildfires, etc., can and already are causing disruptions that can lead to sustained power outages. *See* Exhibit AA-3. More explicitly, extreme weather events pose a significant threat to the reliability and resilience of the U.S. electricity system, and climate change is increasing the frequency of weather-related catastrophic events – including those that stress our electricity infrastructure and expose its limitations. *See* Exhibits AA-4 and AA-5. As the 2018 U.S. National Climate Assessment concludes, "infrastructure currently designed for historical climate conditions is more vulnerable to future weather extremes and climate change." *See* Exhibit AA-6. This same report finds that the nation's energy system will experience increasingly frequent and long-lasting power outages due to a climate-altered future. For the Midwest, the report cites:

- An increase in frequency and intensity of flooding which will threaten energy infrastructure

such as foundations of power lines and riverbank energy facilities;

- More frequent drought which will affect the water supply for power plant cooling, hydroelectric facilities, and cause disruptions to supply chains;
- Rising temperatures which will drive up energy demand for cooling and strain energy systems; and
- More frequent and intense extreme events which will lead to prolonged power outages and cascading societal and economic impacts.

In addition, a 2016 US Department of Energy study on Climate Change and the Electricity Sector enumerates significant impacts that utilities face from climate change (Table 1).

Table 1: Climate Change Hazards for the Energy Sector from US Department of Energy, Climate Change, and the Electricity Sector, 2016

Energy sector	Climate projection	Potential implication
Thermoelectric power generation (Coal, natural gas, nuclear, geothermal and solar CSP)	▪ Increasing air temperatures	▪ Reduction in plant efficiencies and available generation capacity
	▪ Increasing water temperatures	▪ Reduction in plant efficiencies and available generation capacity; increased risk of exceeding thermal discharge limits
	▪ Decreasing water availability	▪ Reduction in available generation capacity; impacts on coal, natural gas, and nuclear fuel supply chains
	▪ Increasing intensity of storm events, sea level rise, and storm surge	▪ Increased risk of physical damage and disruption to coastal facilities
	▪ Increasing intensity and frequency of flooding	▪ Increased risk of physical damage and disruption to inland facilities
Hydropower	▪ Increasing temperatures and evaporative losses	▪ Reduction in available generation capacity and changes in operations
	▪ Changes in precipitation and decreasing snowpack	▪ Reduction in available generation capacity and changes in operations
	▪ Increasing intensity and frequency of flooding	▪ Increased risk of physical damage and changes in operations
Bioenergy and biofuel production	▪ Increasing air temperatures	▪ Increased irrigation demand and risk of crop damage from extreme heat events
	▪ Extended growing season	▪ Increased production
	▪ Decreasing water availability	▪ Decreased production
	▪ Sea level rise and increasing intensity and frequency of flooding	▪ Increased risk of crop damage
Wind energy	▪ Variations in wind patterns	▪ Uncertain impacts on resource potential
Solar energy	▪ Increasing air temperatures	▪ Reduction in potential capacity
	▪ Decreasing water availability	▪ Reduction in concentrating solar potential capacity
Electric grid	▪ Increasing air temperatures	▪ Reduction in transmission efficiency and available transmission capacity

Further, an Energy Information Administration (EIA) report found that the five-year annual average of electrical power outages has been doubling every five years (the period upon which analysis is completed). Dr. Amin from the University of Minnesota's Technological Leadership Institute also found that historically, weather used to account for 17 to 21 percent of all grid interruptions but today, those figures have risen to 68 to 73 percent of all major outages. *See* Exhibit AA-7. Add to this the reality of aging infrastructure, growing demand for electricity as Americans increasingly rely on digital devices, growing seasonal demand for air conditioning, and even greater projected

weather impacts due to climate change and the potential for more intense and longer duration grid interruptions rises significantly.

These problems aren't just a future or distant threat. Earlier this year approximately 156,000 gallons of sewage overflowed into the Saline River due to a power outage. *See* Exhibit AA-8. In August of 2021 severe storms knocked out power for tens of thousands of Washtenaw County families and businesses for five days, forcing the City to redirect staffing resources and services to open emergency relief stations. *See* Exhibit AA-9. While these events may feel extreme, the reality is they are happening more frequently and causing significant health, safety, and economic impacts across Michigan.

In multiple Witnesses' testimonies, the impacts of changing weather patterns and climate change were noted as a concern for DTE. However, it was also stated that the utility has not taken the steps to integrate future projections of climate change into their analysis, modeling, and future decision-making. DTE's decision to not integrate projections of climate change into their planning is a very dangerous approach that almost certainly means that our energy infrastructure will be underprepared for the frequency, intensity, and return interval of extreme weather events and therefore, ratepayers are more likely to experience more service disruptions and associated cascading societal, health, and economic impacts than would have occurred if only the utility had integrated climate projections into their work. This will place a direct and undue burden on local communities across the service territory who will be the ones left to foot the bill and responsibility for cleaning up the mess that could have easily be ameliorated with proper planning and foresight.

Q. Are other utilities integrating climate projections into their modeling and decision making?

A. Yes. Below are examples of utility activities to integrate climate considerations into their planning and operations.

1. Consolidated Edison (Con Ed) has made over $1 billion in investments to fortify its energy delivery systems, including investing in more resilient cables, poles that can withstand winds up to 110 mph, and raising critical equipment out of areas that could flood. The company has also developed a climate resiliency plan and developed a climate change governance structure to fully incorporate climate change into existing processes and practices. This includes adjusting how Con Ed plans and designs infrastructure to ensure it factors in climate change. *See* Exhibit AA-10.
2. Public Service Electric and Gas (PSEG) has made significant investments to enhance reliability and resilience of their energy infrastructure, including making improvements in physical infrastructure as well as green infrastructure to address changes in heat, precipitation, and sea level rise. The company has conducted numerous risk analyses to understand how projected changes in climate will impact their operations and has taken steps to integrate that knowledge into their design decisions, operational frameworks, and daily decision making. *See* Exhibit AA-11.
3. U.S. Department of Defense has taken steps to provide necessary energy and water for a minimum of 14 days in the face of a disruption, at all of its bases. This largely includes onsite renewable energy generation paired with storage, generators, and other decentralized systems. For example, Southern California Edison worked with Fort Irwin Army base to

install a microgrid behind the meter to power critical loads during power outages.

4. The California Public Utilities Commission issued Order 4.18-04-019 in 2018 that requires electric and natural gas utilities to integrate climate change adaptation matters into operations and decision making, while also requiring utilities to complete a climate change vulnerability assessment and identify actions to reduce vulnerability, while setting specific planning standards that must be followed. *See* Exhibit AA-12.
5. The Massachusetts and New York Public Service Commissions passed requirements stating that utilities must plan for climate change impacts. These requirements include a mandate that utilities conduct climate change vulnerability assessments and develop climate adaptation plans. In both states, the Commissions require the utilities to both plan for climate-related impacts but also to plan for reducing climate pollution. Both states require that these assessments and planning efforts must guide future energy infrastructure investments and capital expenditures.

In addition, an assessment of European utilities found that nearly 50% of the measures utilities are taking to prepare for climate change focus on structural improvements, including strengthening infrastructure through microgrids to improve robustness against storms and other extreme events, undergrounding grid infrastructure, and using ecosystem-based adaptation for water management.

Q. Has Ann Arbor experienced the impacts of climate change?

A. Yes. Ann Arbor has worked with the Great Lakes Integrated Sciences and Assessments to model historic, present, and future weather variables and how they have been impacted by climate change. These models show that, over the last 30 years, Ann Arbor has

already experienced significant impacts and changes, including a 44% increase in total annual precipitation, and a 41% increase in the number of heavy precipitation events, including a 37% increase in the amount of precipitation falling during heavy rainfall events. The City has also experienced more than 1°F increase in annual temperature over the last 30 years, with a notable shifting of seasons, an increase in ice falling during winter as opposed to snow, and longer-periods of warmth without respite. *See* Exhibit AA-13.

Q. Has the City had to take any unexpected actions to support residents during power outages?

A. Yes. Last year the City had to open and Emergency Relief Station when many Ann Arbor residents experienced 5 days without power. This involved finding a location big enough for residents in need, ensuring that location had power, finding staff to provide services to residents, securing food, water, and ice for residents, and helping residents get access to real-time services to ensure their safety. And this had to be done at the precise time that staff were having to deal with our own outages and an increase in call volume and support requests from the public due to the extreme weather event. This meant that staff had to stop doing normal business operations and redirect to emergency service provision and support, including the unplanned operation of the Relief Station. Within the Office of Sustainability and Innovations, the unit I oversee, staff were fully redirected for 5 days, including over the weekend, to support residents in the Relief Station. This equates, just within our individual unit, to nearly 400 hours of staff capacity redirected to address a single power outage in the community.

Q. Does the City of Ann Arbor integrate climate change into its utility operations?

A. Yes. Over a decade ago the City of Ann Arbor began integrating climate modeling into its stormwater, water, and wastewater utilities operations. This includes projections of precipitation and temperature changes to ensure we are adequately and safely providing services to our constituents. These models are updated regularly to ensure state of the art climate information is integrated into our business operations.

Q. What do you think the Company should do differently to make sure it is preparing for existing and future changes in climate?

A. DTE could work with institutions such as the Great Lakes Integrated Sciences and Assessment (GLISA), a NOAA funded Regional Integrated Sciences and Assessment, to integrate existing as well as future projections of climate change into their reliability modeling and design specifications. *See* Exhibits AA-14 and AA-15. GLISA has created numerous datasets and tools which could easily, with little to no cost, support the Company with integrating existing climate realities into their planning and support their use of probabilistic future scenarios under a climate-altered future to inform capital, operational, and management decision making going forward. The Michigan Public Service Commission could also require that all regulated Michigan utilities conduct a climate change vulnerability assessment and create plans to address identified risks and vulnerabilities. This would be similar to efforts in other states as mentioned above.

Q. Had the Company previously integrated climate considerations into their operations, do you think it would have saved ratepayers money?

A. Yes. The Company's failure to plan for future changes in climate that are extremely well

documented has meant greater disruptions to service, larger and more sustained impacts to utility infrastructure, redirecting of staff to critical issues as opposed to programmed operations, the loss of hours of work and lower working productivity, and other cascading impacts. For example, had the Company conducted the tree trimming it proposed in previous cases, and was allocated funding to complete, the impacts of the summer 2021 storms would almost certainly have been less severe. Another example relates to managing projected changes in temperature and heat waves in the region. Knowledge of these changes could help the utility manage peak demands more effectively, explore alternative ways to preventatively manage loads to ensure minimal disruptions to the system. Doing this would undoubtedly save rate payers dollars and increase the reliability of the grid, even during extremely warm and prolonged periods of heat.

III. RELIABILITY

Q. Do you believe the proposed case adequately identifies solutions to address reliability?

A. No. While multiple witnesses emphasize the importance of improving reliability, numerous viable pathways to increasing reliability are either eliminated from the testimony or proposals are included within the rate case that would directly decrease reliability.

Q. What activities or pilots proposed in the rate case are counter to the utility's claims about increasing reliability?

A. Science and research from the U.S. Department of Energy, among many other institutions, shows that distributed PV systems, energy storage, and other distributed

energy resources (DERs) can increase community, regional, and utility energy resilience. The distributed nature of solar installation in individual households, businesses, and throughout communities can provide continuity of electricity services when there is grid damage that will cause sustained power outages. During extreme events, which are getting more intense and frequent due to climate change, the power system can be reconfigured into independent segments that each contain load and generation, utilizing PV and energy storage for rapid recovery of critical electricity services. The more installed DERs, the more opportunities for reconfiguration, accelerating energy restoration to enhance grid resilience, and as a result, enhancing community resilience. Distributed PV with long-duration storage can offer even more opportunities to enhance resilience by allowing buildings to continue to power critical loads during sustained power outages.

Moreover, the utilization of DERs, such as distributed PV paired with energy storage, can increase the resilience of energy systems, especially at the distribution level. According to the U.S. DOE, solar power systems, especially those paired with energy storage, are a vastly underutilized resource for providing energy to communities while larger grid-power restoration efforts are underway while also avoiding fuel dependence before, during, and after extreme events. Leveraging existing DERs and incentivizing the expansion of new ones can also be a powerful tool to help manage the reliability of the grid while also saving rate payers money, particularly as it relates to the extreme expenses associated with repowering the entire grid after outages and the costs needed to upgrade the grid to handle future EV adoption and beneficial electrification. Using

existing resources and incentivizing more DERs is far less expensive than undertaking major grid reconfiguration, hardening, or system-wide upgrades.

On their website, the U.S. DOE provides this example of a resilient power system: "A flood forces a local utility substation to shut down, interrupting electrical service. Within seconds, residential photovoltaics (PV) solar panel systems with battery storage automatically detect the loss of grid power and switch to an "islanded" mode to keep the power on. At the same time, a backup battery system at a local fire station enables the utility company to keep its communication equipment on so it can coordinate rescue operations. When the utility company is able to restore service, these backup resources will seamlessly reconnect to the grid, ready to be used during the next incident. A completely resilient electric grid will help communities keep the power on during man-made or natural disruptions." *See* Exhibit AA-16.

Despite this well-known knowledge, DTE is proposing a new tariff structure that directly penalizes DERs. The proposed tariff structure is both draconian and extremely short-sighted. As the U.S. Department of Energy, EIA, the National Renewable Energy Laboratories, and Public Service Commissions across the nation have shown, DERs are a powerful tool to increase reliability, resilience, and long-term affordability of our power system both today and in the future. Instead, the proposed D1.12 tariff structure places a direct fee upon DERs that is neither prudent nor necessary. More likely, it's anti-competitive as discussed below.

Further, according to the calculations presented by Witness Wu, the fee proposed under

the D.1.12 tariff structure for DERs would treat excess energy generated through rooftop solar systems as waste – waste that the utility argues is nearly 20 times more expensive to dispose of than coal ash (see Testimony of Fang Wu.) This is nonsensical. DTE should be working to incentivize DERs and energy storage systems to help ensure resilience and reliability of the grid instead of directly penalizing residents and businesses for paying for assets that provide a clear, direct, and important reliable energy source.

Q. Are there other examples of proposed activities that negatively impact reliability and place an undue burden on ratepayers?

A: Yes. While the City is excited to see non-wires alternatives (NWA) pilots proposed in this rate case, we find that the storage and microgrid pilots are, in particular, incomplete, underdeveloped, and out of lock step with industry best practice.

Q. Please explain why you believe the residential battery storage pilot is out of step with industry best practice.

A. While another witness for the City will provide more direct testimony on this topic, our primary concerns with the proposed residential battery pilot include:

- Extremely high rates for subscribers without providing them the full suite of benefits batteries can provide, including those stated by Witness Morren: “energy production, peak saving, voltage support, and energy storage, all of which benefit our customers.” While residents would have access to the critical back up feature of batteries, the utility would have access to all the other benefits. Yet the customer would be asked to bear the full cost of those batteries without reaping the full benefits.

- The pilot solely relies on new battery storage units as opposed to leveraging existing installed units. This fails to use assets already within the system, which would very likely be cheaper, lead to quicker learnings, more rapid estimated cost proposals and proposed treatments, and a much more rapid turnaround time to full program design and launch for new deployments. This is particularly confusing given that the company claims that they want to cluster batteries together "to achieve the level of storage required to obtain targeted NWA learnings." There are multiple circuits within the system, especially within Ann Arbor, that already have high rates of customers with existing battery storage. These tend to be the circuits that meet the requirements identified in Witness Burns' testimony for citing due to the reality that residents in these circuits regularly lose power and have resorted to battery storage to help manage outages. These circuits could be rapidly studied to understand the value of a residential battery storage program with minimal cost and administrative actions from the Company. Moreover, Witness Burns states that one of the goals for the battery pilot is to "understand incentive structures and facilitate the Company's learnings around how to use batteries to manage load." A Bring Your Own Device ("BYOD") pilot would help the Company immediately begin learning about the best way to use batteries on the system with very low costs. Given the real and significant impacts rate payers are already seeing for extreme weather events and associated power disruptions, it seems prudent to start a residential battery pilot with existing devices.
- The proposed pilot, for residents that have DERs or are interested in deploying them, directly works against the proposed D1.12 rate. In these cases, customers will likely have noncoincident demand charges that mean they are paying a premium for energy as compared to non-solar users. See Witness Wu's testimony for greater detail.

- The Company appears to be proposing a pilot that is not cost of service based but is seeking to extract as much money out of customers experiencing frequent power outages as possible. As Witness Burns clearly states: (pg. 230) "Tiered pricing allows for testing of customer interest at different price points to better understand customers' willingness to pay for backup power. Comparing speed of uptake for different monthly fees…will help determine appropriate pricing strategies for resiliency as a service." Resilience ***IS*** the service of utilities. It is their job to ensure that resilient, reliable power is provided to rate payers. Payers should not be charged a premium to receive the power they pay for. Nor should the utility be looking price gouge to provide that resilient, reliable source of power. These pilots must be cost of service and reflect the true price for the services residents are receiving. This means that if a resident is only getting back-up power supply when the grid goes down, they should not be charged for the energy production, peak shaving, voltage support, and load management features that batteries provide since they aren't getting those benefits.
- The Company hasn't identified the price point upon which it will be offering the residential battery storage program. Approving this pilot with a potential range of pricing from $29.99 to $49.99 per month leaves too much uncertainty in the market. Moreover, as Witness Grocoff will further elucidate, the cited Green Mountain Power battery pilot had very different support than what is reflected in Witness Burns' testimony. Green Mountain Power encourages solar and storage to help residents island during power outages and projected their costs to be much lower than the "sticker price" – and many participants ended up receiving a credit. Green Mountain Power's program offers a "bring your own device" feature so that residents can participate with their own battery – not just a utility

owned system, which has lowered the costs of the pilot and ensured competitive opportunities for different manufacturers. *See* Exhibit AA-17. In direct testimony, Witness Burns notes that (page 233), "The pilot does not offer a (bring your own device) BYOD segment to start because the Company does not yet understand the appropriate incentive structure that should be offered to these customers." This runs contrary to the Company asking for funding to start the utility-installed and owned battery pilot without knowing the price or appropriate incentive structure. Moreover, it was expected the Company would have referenced the learnings related to price from Green Mountain Power, which show that the monthly price is significantly lower than what is cited in the Company's testimony (and even lower for those that bring their own devices). Finally, while stated previously, the City finds it particularly egregious that the proposed residential battery pilot seeks to determine customers' "willingness to pay for resilience as a service." It is the job of the utility to provide resilient and reliable power, and DTE customers are already paying some of the highest rates in the Midwest for that power. Having resilient and reliable power should not be a privileged service that only the wealthy can access. Nor should the utility charge residents excess for a service they are already being paid to provide. As such, I find the pilot to be poorly constructed, not cost of service based, and out of step with industry best practices.

Q. What types of changes would you hope to see in the proposed residential battery storage pilot?

A. As indicated in my testimony above, there are numerous flaws with the proposed residential battery storage pilot that could easily be addressed. First, the Company needs to fundamentally rethink the purpose of the pilot and therefore its structure. Focusing on

a customers' willingness to pay for resilience is unacceptable. Focusing on the role batteries play in ensuring resilient and reliable power is provided to rate payers is an acceptable purpose. If this were the goal, then the Company should be looking to leverage a bring your own device program, setting pricing that is representative of the true cost of the battery and that factors in the full suite of benefits that batteries offer, ensure that the subscriber gets access to the full suite of benefits or is only charged for those benefits it receives, and the company would discard the D1.12 rate which will unequivocally curtail the installation of resilient DER systems in the private market.

Q. Please explain why you believe the proposed microgrid pilots are out of step with industry best practice.

A. As cited previously, multiple lines of research and practice have found that microgrids improve reliability and resilience. *See* Exhibits AA-16 and AA-18. While we are delighted to see a microgrid pilot in the current case, we believe if falls short of the scale and scope necessary to be a meaningful contribution to the Company's aims around reliability enhancements and preparation for FERC Order 2222. And the true costs of this project are hard to decipher given the convoluted nature of the proposal.

More specifically, my experience working in collaboration with the designers of the Customer Load and DER Control project being proposed for testing (Veridian), show that the pilot does not meet the project objectives, would not lead to a true microgrid capable of islanding and sharing power amongst the developments on this site, and has been designed by the utility to intentionally be of a prohibitively high cost so as to destroy the viability of future microgrid projects. For more details, please see Witness Grocoff's

testimony. Moreover, the Company's continued push to disincentivize DERs and directly penalize those that invest in DERs mean that ratepayers are being asked to pay far too much for new assets when non-poles and wires alternatives (or limited poles and wires alternatives) to increase resilience and reliability of power supply already exist on the system.

Q. Are there other utility models for microgrid deployment that you would recommend the Company consider?

A. Yes. A 2022 report by NARUC highlights multiple efforts underway in States across the U.S. to deploy microgrids for resilience and reliability enhancement. This report discusses efforts in Rhode Island, Wisconsin, Connecticut, Maryland, Massachusetts, New Jersey, New York, California, and Kentucky. A notable example is the Bronzeville Community Microgrid in Illinois, (operated by ComEd) which unites public safety and administrative services with residential users into a neighborhood-level microgrid that uses solar PV, battery storage, diesel, and controllable natural gas generation. Another example is the 2019 Duke Energy deployment of a microgrid consisting of 2-MW solar installation and a 4-MW battery storage facility in Hot Springs, NC, which is located at the end of a 10-mile feeder line prone to outages. Duke found the project to have improved reliability while also providing "energy and additional bulk system benefits for all customers," including frequency and voltage regulation, ramping supporting, and peak capacity. Deployments such as they lessen, and in some cases completely ameliorate, the need for costly improvements to the grid, thereby effectively managing costs for ratepayers and increasing the reliability and resilience of the power supply.

Additionally, great lessons can be learned from the U.S. Department of Energy who has been working to develop microgrids on bases throughout the world. Examples include Naval Construction Battalion Center in Gulfport, MS which includes a 4.3MW PV system, battery storage, and diesel generator, as well as Pacific Missile Range Facility in Barking Sands, Hawaii which includes a 14MW PV system and 70 MWh battery storage system.

Another notable example is in Hawaii. In 2021, Hawaii regulators approved a microgrid services tariff outlining rules for customer microgrids, where customers own all generation, storage, distribution, and related infrastructure to supply their own energy needs, and hybrid microgrids, in which customers provide some of all of their own energy through customer-owned generation while using some utility-owned distribution infrastructure to provide power. *See* Exhibits AA-19 and AA-20. The PUC noted this program would improve reliability and provide numerous benefits to all rate payers.

Q. Is Ann Arbor interested in deploying microgrids?

A. Yes. The City of Ann Arbor is extremely interested in deploying microgrids to help improve energy reliability and resilience, while also supporting the transition to a clean energy economy and lessening the cost of traditional large-scale grid improvements to address reliability. More specifically, the City sees a very real and immediate need to deploy DERs and microgrids throughout the system to help lessen the demand on the centralized grid infrastructure and manage the increasing demand coming to many of our circuits due to electric vehicle adoption and beneficial electrification. For example, in 2021 DTE announced a $20 million dollar investment to upgrade one 4.8kV system to

handle electrification. *See* Exhibit AA-21. Dispatching energy storage systems throughout this circuit, potentially paired with onsite solar at many sites, likely would have been a much cheaper solution to reliability concerns and helped to enhance resilience during power outages. This circuit, and likely many others in Ann Arbor, would also be prime candidates for microgrid deployment and testing. Finally, because of the high adoption rate of solar and storage in Ann Arbor, as noted in the report DTE commissioned from Emicity and ICF Consulting, Ann Arbor already has a significant portion of the infrastructure necessary to deploy microgrids, making it an ideal location to test the concept with minimal cost and risk to other rate payers. This claim appears to be substantiated by the testimony of Witness Pfeuffer, stating "non-wires alternative (NWA) pilots indicate that NWA solutions can provide a benefit by reducing the scale of the traditional solution or by deferring it for a number of years…"

Q. In your opinion, is the Company's proposed tree trimming sufficient to address reliability concerns?

A. No. While proper tree trimming is an important feature of preventative maintenance, tree trimming alone is insufficient to address reliability. In August of 2021, thousands of residents of Ann Arbor experienced a multi-day power outage, including neighborhoods that had just experienced extensive tree trimming. In one example, a neighborhood in the 5th Ward of Ann Arbor had recently experienced extensive (and potentially problematic amounts of) tree trimming when a large storm moved through, knocking power out to the entire neighborhood. DTE representatives shared with the constituent and an elected official that "more severe storms are resulting in entire trees failing over and the trees that

were problematic in the 5th Ward were often not even in the ROW (right of way).” This example illustrates why tree trimming alone is insufficient to address reliability concerns. Undergrounding of utility infrastructure, significant investments in non-wires alternatives such as onsite solar and storage, and proper and regular tree trimming will all be necessary to improve reliability and save rate payers dollars in the face of today’s climate, as well as the climate of tomorrow.

IV. ANTI-COMPETITIVE BEHAVIORS

Q. Do you believe the Company’s proposed treatment of distributed generation customers is fair and appropriate?

A. No. I find that the proposed D1.12 rate is not only unnecessary and imprudent it is effectively an exit fee applied only to customers that install distributed energy systems. Moreover, as the Company’s own funded study found, customers that are pursuing solar, as well as solar and battery storage systems are largely concentrated in Ann Arbor and are investing in those systems due to the unreliability of the current grid. The proposed D1.12 rate looks like a direct tax or exit fee on Ann Arborites interested in self-supplying reliable and resilient power.

Moreover, as mentioned previously, the Company could have chosen a path to work directly with rate payers to install more DERs to manage reliability and increase resilience but has, instead, opted for a path that directly penalizes anyone for moving forward with solar outside of a utility program. More specifically, the impact of the designed D1.12 rate structure will directly impact private solar companies by intentionally making distributed solar resources far too expensive and pushing climate

conscious ratepayers into the MIGreenPower program (See Witness Wu's testimony on costing). Not only is this anti-competitive, it's also short sighted. As we are seeing in DTE territory, as well as across the nation, citing utility-scale renewable energy projects is getting extremely complicated. Failing to support ratepayer initiated DERs means that the utility is putting all its emphasis (even though anti-competitive) into utility-scale systems which are challenging to site and often take up important greenfield land. At some point, support for these projects will wane and the state, Company, and communities will likely be left will little financially viable alternatives. This will undoubtedly raise the cost of achieving the necessary clean energy goals and force rate payers to pay higher rates for suboptimal solutions when viable alternatives, such as leveraging and encouraging more DERs, were possible.

Q. Please elaborate on why you find the proposed D1.12 rate to be an exit fee.

A. My reading of the proposed D1.12 rate is that it is a clear fee on solar energy generators used to discourage those systems. The analysis in Witness Wu's testimony substantiates this conclusion. Moreover, the Company makes it explicit that only solar customers are required to go on the D1.12 rate while all other customers will have a choice. This gives no option to solar installers, forcing them to subscribe to the most expensive rate that is designed to penalize rate payers with solar, while all other ratepayers have options.

In addition, the offer to increase the DG cap from 1% to 3% if the D1.12 rate goes through is a false solution that ignores the desires of stakeholders, the movement of the market, and the realities of the clean energy industry. If the D1.12 rate structure were to go through, the local DG industry would be annihilated making achievement of the cap

moot. The Company clearly knows this so is not offering a solution in good faith but is instead trying to trap the Commission, intervenors, and rate payers into a pathway that forces all customers interested in renewable energy into the MIGreenPower program. And the Company's proposal to create a rooftop solar calculator, as indicated in Witness Wu's testimony, that tells ratepayers about the impact of rooftop solar, but only about rooftop solar that would be required to be on the D1.12 rate, not rooftop solar that could be on the Rider 18 rate, is anti-competitive. This decision means that today's ratepayers will never get the benefit of knowing that rooftop solar is a cheaper option than the MIGreenPower program and can have a 11-year payback on a 25-year asset. Instead, DTE will only tell ratepayers about rooftop solar systems when they have created rate structures that make it uncompetitive.

The Commission should deny this rate structure and ignore the Company's insincere offer to increase the DG cap, since the proposed D1.12 rate makes that cap irrelevant. This program would hurt ratepayers and the Michigan economy.

Q. Would the proposed D1.12 tariff negatively impact Michigan local solar industry?

A. Unequivocally. After the rate case was released the City of Ann Arbor convened the solar installers that participate in our Solarize program to understand the impact of the proposed D1.12 rate change on their industry. From what I have learned in the course of my position, if the DTE rate proposal was approved, the residential solar installation industry would effectively cease to exist. I believe solar installations will reduce drastically, as much as 60%; and many people will switch to a no sell back system with excess power stored in a battery. Workforce reductions are also likely.

The local Michigan solar installation field is strong and thriving. The proposed change by DTE would have a chilling effect on the industry at the precise time it is growing and the services it provides are gaining in popularity and necessity. Given the Governor's commitment to the MI Healthy Climate Plan, President Biden's commitments to climate action and renewable energy deployments (especially DER), and increasing local community clean energy commitments, it is unclear why the Company would propose such a draconian rate if it were not explicitly trying to stymie competition.

Q. Are there are topics in the Company's testimony that you believe are further indicative of anti-competitive behavior?

A. Yes. Witness Pizzuti notes that the Company is investing "$0.7 million in projected test period capital….to support efficient, real-time monitoring of MIGreenPower and private solar data." The Witness, however, did not send any justification as to why the monitoring of private solar data was necessary. Moreover, the reports commissioned by the Company to understand solar PV adoption amongst stakeholders included language that directly pushed customers towards MIGreenPower instead of distributed generation. As Witness Wu's testimony reveals, the MIGreenPower program is an expensive program that does not have the same social, economic, and environmental benefit as DERs. Omitting this information and creating programs that are intentionally designed to reduce the competition from private solar installers, following surveys of customers paid for by ratepayers that gathered information about how to market such programs, is the definition of anticompetitive.

Q. Is a rate increase appropriate at this time?

A. I appreciate that the Company has the legal right to request rate increases, and I understand the need to prepare our infrastructure for changes in climate. However, the Company has failed to holistically integrate climate considerations into their modeling and decision making and is asking for a rate increase during a time when the Company's revenue exceeded expectations for residential customers. This is because residential customers bore the brunt of the pandemic and were largely displaced to spending more time working and operating at their homes. Asking for a rate increase at this time is both tone deaf and extremely damaging to families and businesses that are hurting and still trying to recover from the effects of continuing pandemic.

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.

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Melissa Stults

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.	U-20836 ALJ Sharon Feldman

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DIRECT TESTIMONY OF FANG WU

ON BEHALF OF

THE CITY OF ANN ARBOR, MICHIGAN

May 19, 2022

I. INTRODUCTION AND BACKGROUND

Q. Please state your name and business address.

A. My name is Fang Wu, and I am the Energy Manager in the City of Ann Arbor. The business address is 301 E. Huron Street, Ann Arbor, Michigan 48104.

Q. Are you offering this testimony as a lay witness or as an expert witness?

A. I am offering this as both a lay and an expert witness. I have educational and professional expertise in economics and energy, but other aspects of my testimony is based on personal knowledge gained in my work as an employee for the City of Ann Arbor, where I have day-to-day responsibilities that include analysis of energy options for residents.

Q. Please describe your educational background and professional experience.

A. I hold a bachelor of science in economics from the Zhejiang University of Technology. I also have a Master of Science degree in Applied Economics and a minor in statistics from the University of Minnesota. I also received my Master of Business Administration degree from the Krannert School of Management at the University of Purdue.

In 2007, I began to work at the Minnesota Department of Agriculture as a program manager, where I executed marketing research projects and feasibility studies for agricultural communities and administrated USDA block grants in Minnesota. In 2011, I began to work for HDR Inc. as a senior economist, where I provided cost-benefit analysis and risk analysis for large infrastructure projects. In 2014, I went to Purdue University and worked as a Data Scientist with the State Utility Forecasting Group for six years. I

developed independent load forecasting for MISO, provided forecasting modeling, and integrated resource planning for the Indiana Utility Regulatory Commission. I began my current position for the City of Ann Arbor in July of 2020. In my role for the City, focus on energy policies and programs to reduce community-wide greenhouse gas emissions in a just and equitable manner.

I have also attended the Advanced Regulatory Studies Program and Rate Making Course hosted by the Institute of Public Utilities at Michigan State University.

Q. On whose behalf are you submitting your testimony in this proceeding?

A. My testimony is on behalf of The City of Ann Arbor, Michigan ("Ann Arbor" or "City"). Ann Arbor is a member of the Michigan Municipal Association for Utility Issues (MI-MAUI).

Q. Have you previously testified before this Commission or as an expert in other proceedings?

A. Yes. I have previously testified related to DTE Electric's voluntary green pricing (VGP) plan in case No. U-20713.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the proposed residential D1.12 rate schedule and changes in the distribution generation (DG) tariff proposed by DTE Electric Company ("DTE"), and residential customer data access more broadly.

The following is a summary of my concerns regarding the proposed changes to the Rider

18 program. In support of my concerns, I provide a bill impact analysis based on actual customer billing data under various scenarios.

- The proposed rate changes create new incentives for customers to increase system costs by using more electricity during peak hours, thus increasing the need for more expensive generation, distribution, and transmission infrastructure.
- The proposed rate changes penalize new solar customers[1] who are exercising their rights to self-supply by imposing a demand charge that imposes costs on such customers that are unrelated to the actual effect on the system, essentially functioning as an exit fee. As discussed below, new solar customers would have increased capacity and distribution charges under the proposed D1.12 rate schedule than what they pay today. Their contributions to reducing grid costs (for instance, by avoiding peak usage) are not recognized.
- The proposed rate structure appears to be designed to penalize customers exercising their right to self-supply to reduce their carbon footprint by making DTE's MIGreenPower program more competitive. DTE's materials show this is likely part of a deliberate attempt to eliminate competition.
- Current data access service for solar customers thwarts the ability of average customers to weigh the true costs of self-supply vs. other options.

[1] "A new solar customer" refers to a customer who installs a PV system after "At the later of either the Company hitting any of the category-specific reservations established through MCL 460.1173(3) or the first quarter of 2024,…At that time, all new Rider 18 resdiential customers will be required to take service under D1.12 and their DG installation, and Rider 18, must be associated with their D1.12 service." (Witness N. Foley testimony, page 63, line 9.)

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit AA-22	Fang Wu CV
Exhibit AA-23	Costs of Running a Bitcoin Mining Machine 24/7 vs. EV Charging
Exhibit AA-24	Discovery response AAMDE-2.11dc
Exhibit AA-25	Discovery response GLREADE-3.34c
Exhibit AA-26	Ford F-150 Lightning Frequently Asked Questions
Exhibit AA-27	Discovery response (first partial response) AAMDE-2
Exhibit AA-28	Discovery response (first partial response) AAMDE-2.13 cc
Exhibit AA-29	Discovery response AAMDE-2.10
Exhibit AA-30	Bill Impact on Solar Customer E and F
Exhibit AA-31	Discovery response MNSCDE-2.34
Exhibit AA-32	Discovery response AAMDE-3.20e
Exhibit AA-33	Michael Witkowski, Impact of Proposed EV Ordinances to Electrical System, DTE, May, 2020
Exhibit AA-34	Voluntary green power programs offered by other MI utilities
Exhibit AA-35	Discovery response MNSCDE-2.34-01
Exhibit AA-36	Discovery response AAMDE-2.12a and 2.12b

Q. Were these exhibits prepared by you or under your supervision?

A. Yes. I prepared the exhibits using public information and actual customer data provided by DTE's residential customers.

Q. Have you reviewed DTE's Rate Case U-20836 Filing?

A. Yes.

II. THE IMPACT OF THE PROPOSED D1.12 PRICING AND CHANGES TO THE DISTRIBUTED GENERATION TARIFF

Q. What is the average cost of electricity in the Detroit-Warren-Dearborn Michigan metropolitan area, according to the Bureau of Labor Statistics?

A. Over the last four years, the average price of electricity in that area has ranged between approximately 15 and 18 cents, as shown in the table below, which summarizes data found at https://www.bls.gov/regions/midwest/news-release/averageenergyprices_detroit.htm.

Period	Average Price for Electricity
Mar 2018	$0.164
Mar 2019	$0.147
Mar 2020	$0.164
Mar 2021	$0.175
Mar 2022	$0.178

Q. What new incentives for customers would result from the cost estimation structure of the proposed Rate Schedule D1.12?

A. The proposed method to estimate the monthly capacity and distribution charges (referred to as "demand charge" hereafter) rewards cost-causers by rewarding customers to use more electricity during peak hours and shifting those costs onto customers that are likely to shift their usage away from the peaks. For instance, it penalizes solar customers and customers who adopt EVs compared to customers to overall increase their usage. Such additional usage adds a burden to the generation, distribution, and transmission infrastructures that the rate structure would shift to other customers taking measures to

avoid peak usage.

I will illustrate the bill impact on the following residential customers based on their energy consumption behaviors, assuming the approval of the D1.12 rate schedule and distributed generation ("DG") tariff:

- Customer A: A non-DG residential customer who begins to run a Bitcoin mining machine 24/7 all year long;
- Customer B: A non-DG residential customer who buys an electric vehicle ("EV") and uses a Level 2 charger;
- Customer C: A new solar customer who also buys an EV and uses a Level 2 charger at off-peak hours.

My analysis assumes these customers otherwise do not change their energy consumption behavior related to the use of other electric appliances due to these additions. Thus, their top three nonconincident peak demands from their prior usage don't change. Table 1 below summarizes the actu each customer's actual additional demand charge e proposed D1.12 rate schedule and under the D1 rate schedule. Exhibit AA-23 illustrates the assumptions and calculation of the additional monthly charges of Customers A and C.

Table 1: The Costs of Bitcoin Mining vs. EV Charging under the Proposed D1.12 Rate Schedule

Variables	Bitcoin Miner (a)	Non-DG Customer EV Charging (b)	Solar Customer EV Charging (c)	Item number
Hourly kW usage	3	3	3	(1)

Variables	Bitcoin Miner (a)	Non-DG Customer EV Charging (b)	Solar Customer EV Charging (c)	Item number
Annual kWh usage from the grid	26,280	3,902	1,951	(2)
D1.12 Stable bill service rate				
Additional Monthly Capacity charge at $5.85 per kWh	$17.55	$17.55	$17.55	(3)=$5.85x(1)
Additional Monthly Distribution charge at $10.76 per kW	$32.28	$32.28	$32.28	(4)=$10.76x(1)
Average capacity charge per kWh	$0.008	$0.054	$0.108	(5)=(3)/(2)
Average distribution charge per kWh	$0.015	$0.099	$0.199	(6)=(4)/(2)
Non-Capacity charge range ($/kWh) (off-peak to peak)	$0.047 to $0.064	$0.047 to $0.064	$0.047	(7) proposed charge
Power supply+Distribution charge ($/kWh)	***$0.07 to $0.087***	***$0.2 to $0.217***	***$0.353***	***(8)=(7)+(5)+(6)***
D1 standard residential service rate				
Non-Capacity charge ($/kWh)	$0.049	$0.049	$0.049	(9) proposed charge
Capacity charge ($/kWh)	$0.056	$0.056	$0.056	(10) proposed charge
Distribute charge ($/kWh)	$0.082	$0.082	$0.082	(11) proposed charge
Power supply+Distribution charge ($/kWh)	$0.186	$0.186	$0.186	(12)=(9)+(10)+(11)
Additional Monthly Capacity Charge ($)	$121.85	$18.09	$9.05	(13)=(10)x(2)/12
Additional Monthly Distribution Charge ($)	$179.44	$26.64	$13.32	(14)=(11)x(2)/12
Savings: D1.12 vs. D1				
Monthly capacity charge saved ($)	$104.30	$0.54	($8.50)	(15)=(13)-(3)
Monthly distribution charge saved ($)	$147.17	($5.64)	($18.96)	(16)=(14)-(4)
Percentage savings	83%	-11%	-123%	(17)=100%x[(15)+(16)]/[(13)+(14)]
Annual savings with D1.12	***$3,017.64***	***($61.14)***	***($329.55)***	***(18)=[(15)+(16)]x12***

As shown above, Customer A runs a Bitcoin mining machine at home 24 hours a day all

year long. The machine uses 3 kW per hour constantly. This adds 3 kW to Customer A's peak load. Based on the proposed demand charges, one additional kW peak usage will add a $5.85 capacity charge per month, and a $10.76 monthly distribution charge. Therefore, for Customer A the additional demand charges to run the mining machine is $50 per month on the proposed D1.12 rate. If Customer A is served by the proposed D1 rate schedule, which charges based on volumetric usage, the additional monthly capacity and distribution charges would be $300 per month. By voluntary enrolling in D1.12 instead, Customer A saves over $3,000 annually for Bitcoin mining, even though that increases the load on the peak. The average electricity cost Customer A pays is less than $0.09/kWh, well below the average costs for our area.

Customer B has an EV and charges with a Level 2 charger which consumes 3 kW per hour. All else equal, it adds 3 kW to Customer B's peak load. Therefore, Customer B pays the same additional monthly demand charge as Customer A pays. Please note Customer A uses six times more electricity than Customer B does overall. The average cost to charge Customer B's EV would be more than $0.20/kWh under D1.12. It is 150% more than what Customer A pays to run its server. If Customer B stays with the D1 rate schedule, the additional capacity and distribution charges would be $45 per month, which is 10% less than charged under the D1.12 rate.

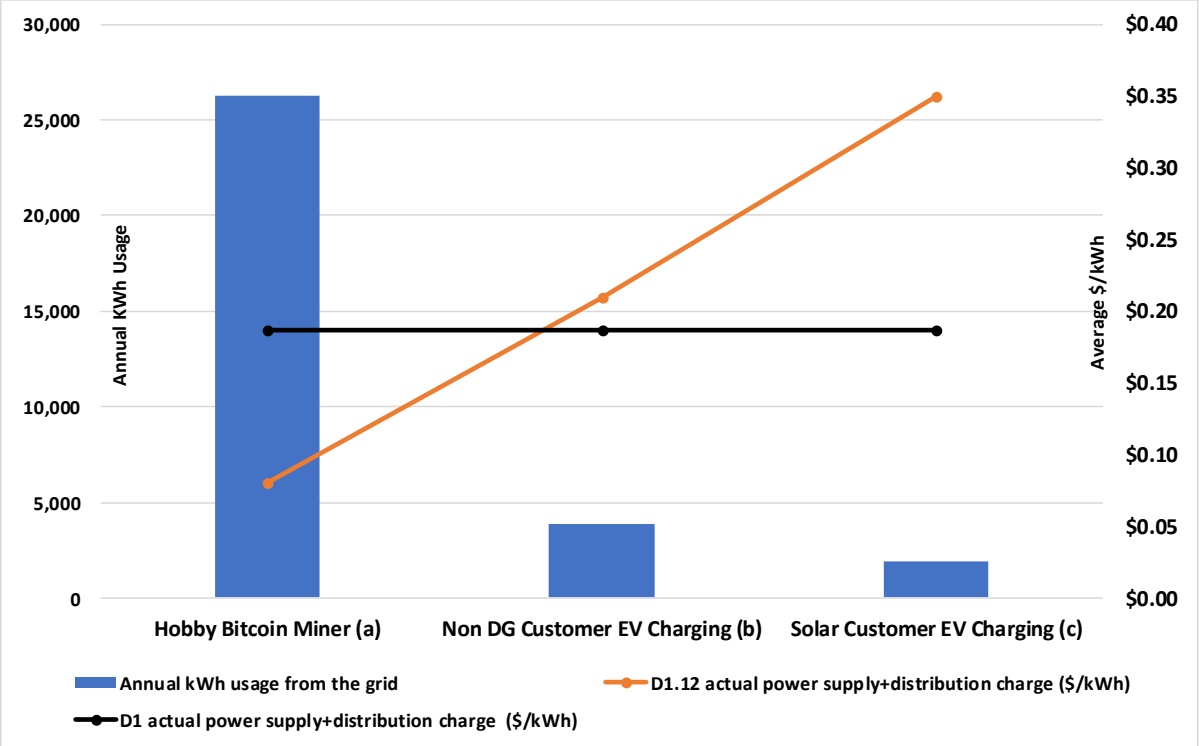
Customer C has a rooftop solar system and an EV. Customer C charges the EV with a Level 2 charger which consumes 3 kW per hour. Customer C charges the EV using the electricity generated from the rooftop solar 50% of the time. When there is no solar generation, Customer C charges the car using the power from the grid during off-peak

hours. As with Customer B, charging the EV adds 3 kW to Customer C's peak demand. Customer C pays the same additional demand charge as Customer A and B pay, but consumes less than 10% of the energy Customer A used for Bitcoin mining and 50% of the kWh Customer B used for EV charging. Under the proposed D1.12 rate, the actual electricity cost Customer C pays for EV charging is more than $0.35/kWh. That is more than 300% more than what Customer A pays for Bitcoin mining under the same tariff, even though Customer C contributes much less to the system peak and demands on the infrastructure overall. If Customer C takes service under the D1 rate schedule, the additional capacity and distribution charges would be only $22 per month -- which is 55% less than the charge under D1.12. Therefore, Customer C is highly disadvantaged under the D1.12 rate compared to the standard rate, and highly disadvantaged compared to customers that contribute more to system costs simply because Customer C chose to exercise a right to self-supply. DTE's proposal to make this higher cost mandatory for DG customers but not for other customers who cause similar or higher costs operates as a fee or charge for the transition to and implementation of self-service power.

As D1.12 is a voluntary residential rate schedule for non-DG customers, customers can choose a rate schedule that could provide the most bill savings based on their energy usage and consumption behaviors. According to the scenario analysis, only Customer A would want to enroll in D1.12 as it could generate significant savings. Customers B and C would be better off staying with the D1 rate schedule. However, based on the changes to the Rider 18 program DTE proposed, Customer C does not have the flexibility to choose the best rate schedule and must enroll in the D1.12, which will result in charges of

more than $0.35/kWh to charge the EV – more than double the average energy cost over the past four years, and despite charging the vehicle during non-peak hours. Chart 1 below displays the actual electricity cost per kWh DTE charges to Customers A, B, and C under the proposed D1.12 in different scenarios.

Chart 1: Actual D1.12 Charge per kWh for Bitcoin Mining vs. EV Charging



The scenario analysis demonstrates multiple issues with the proposed D1.12 rate schedule design. Customer A uses six times more electricity than Customer B and 12 times more than Customer C. Customer A also adds demand to the grid during peak hours and constantly adds demand to the substation transformer. However, because of the design of the proposed D1.12 rate, the Hobby Bitcoin Miner is significantly advantaged over the EV drivers – the Bitcoin miner pays the lowest electricity cost per kWh and generates significant savings by taking service under the D1.12 rate schedule. This shows the way

the D1.12 rate effectively operates as a fee for self-supplying energy from a DG system rather than as a reflection of the true cost of service.

Q. Can DG customers elect to remain on the D1 rate?

A. No. The proposed rate structure does not allow customers who self-supply some of their electricity from a DG system to escape these high costs. New solar customers "will be required to take their whole home, base service on Rate schedule D1.12" (Witness A. Willis, page 21-22). They get severely penalized because the new rate is based on noncoincident peak demand -- so even though they greatly reduced their demand from the grid, especially during peak hours, they will be charged even more than customers that do contribute at peak. DG users get further penalized under the rate if they adopt an EV or switch out fossil fuel-burning appliances with high-energy-efficient electric ones; non-DG customers that elect an EV or switch out appliances pay a much lower cost for those decisions because they can elect service under other tariffs.

Q. Can solar customers reduce their noncoincident peak demand after installing a rooftop solar system to reduce the disproportionate cost increases they would otherwise experience under D1.12?

A. It is unlikely that a solar customer would reduce their noncoincident peak ("NCP") demand. Solar power generation depends on the weather, sunlight, hours of the day, and the seasons of the year. Solar customers must use electricity from the grid like non-solar customers at night or on cloudy, rainy, and snowy days. Therefore, it is unlikely for a solar customer to reduce the noncoincident peak load.

In response to the discovery, DTE Witness N. T. Foley (AAMDE-2.11dc) did say otherwise, although this is not consistent with other DTE testimony. In response to discovery, DTE said that such customers "could be able to reduce their monthly capacity and distribution charges if their average top three highest use hours were to decrease month-to-month" such that the customer moved to a lower service level. However, DTE's analysis shows the extreme unlikelihood of this occurring that the same witness cited supporting the D1.12 tariff. DTE's analysis was based on the aggregated usage of 342 solar customers that began taking service under Rider 18 at some point in 2019 and took D1 service in 2018 before installing their DG system. In his testimony about this empirical study, Foley noted "customers who installed their DG system and took service under Rider 18 did not meaningfully reduce their average monthly NCP demand." *Id.* at NTF-59.

Knowing the DG customers are unlikely to reduce the noncoincident peak after the solar system installation, the proposed D1.12 rate effectively penalizes customers who self-supply by imposing a demand charge based on noncoincident peak demand. Secondly, it does not provide new solar customers with an alternative rate schedule that can reasonably monetize their contribution to demand reduction, peak shaving, and reduction in the energy demand to substation transformers during peak hours. As such new solar customers must pay the same demand charge as the charge before they install their solar systems, even though they use much less energy from the grid and help shave the system peak load by uploading excess generation to the grid and reducing demand from the grid.

Q. Will the proposed D1.12 rate schedule impede the adoption of EVs among

residential customers?

A. Yes. Witness Foley states in the testimony on pages 34-35: "As customers become more sophisticated and tools to actively manage usage become more mature, providing additional ways for customers to control the size of their bill can have tremendous value." Per the DTE's response to discovery question GLREADE-3.34c, several examples of tools include, but are not limited to:

- "Smart" Thermostats;
- "Smart" electric clothes washers and/or electric cloth dryers.
- DTE Insight App

While a "sophisticated" customer can use those tools to stagger the energy usage, and some vehicles allow the customer to avoid ever charging at peak, the tools DTE cites cannot be used to stagger the EV charging in a way that never increases the NCP demand. Once you plug in the EV, a Level 2 EV charger uses 3kW to 19KW per hour. The new Ford-150 Lighting pick-up takes 17 hours to get a full charge with an 11.5kW/80-amp output for a 320 mileage range. *See* Exhibit AA-26. Once plugged in, it pulls 11.5kW from the grid. No matter how the customer staggers the usage of other appliances, it is impossible to keep the NCP demand less than 11.5kW. Suppose the customer doesn't use other appliances when charging the EV, but the always-on kWh usage (e.g. refrigerator and lights) is about 0.5kWh. The Lightning owner's NCP load will always be at least 12kW. Suppose the customer's NCP load is 5 kW before adopting the EV. Their annual additional demand charge would be about $1,400 due to EV charging, *no matter when* they charge the EV, or for how many hours. Table 2 below

illustrates the actual cost of charging the Lightning F-150 pick-up at home under the D1.12 rate schedule.

Table 2: The Cost of Charging a Ford Lightning Electric Pick-up 150 at Home using a Level 2 Charger

Variables	No EV (a)	Charge EV at home (b)	Notes
Monthly NCP (kW)	5	12	(1) Assumption
Average top 3 NCPs	5	12	(2) Assumption
Monthly capacity charge ($)	$29.26	$70.22	(3) D1.12
Monthly distribution charge ($)	$53.78	$129.08	(4) D1.12
Annual capacity charge + distribution charge ($)	$996.48	$2,391.60	(5)=(3)+(4)
Additional demand charge due to EV charging		***$1,395.12***	***(6)=(5)b-(5)a***

Though the analysis is based on a hypothesis, it shows how the proposed demand charge based on NCP may hurt EV owners, thus impeding EV adoption among residential customers under the proposed D1.12. For non-DG customers, they are eligible to choose other rate schedules that do not impose an NCP demand charge. However, per the proposed changes in Rider 18 program, new solar customers are required to take service under the D1.12, which makes EV charging more expensive for them. Thus, those customers who have chosen to adopt an EV and self-supply would pay a much higher electricity price than average (or than other EV users).

Q. In your experience, do Ann Arbor residents who chose to self-supply with solar also have strong interest in EVs, since both are ways to reduce their carbon footprint and reliance on fossil fuels?

A. Yes. However, under these tariffs, people who self-supply carbon free energy would have to pay significantly more to fuel their EV than those who do not, even though such

DG customers would likely reduce the summertime peak loads on the grid more than EV driving, non-DG customers.

Q. Can you please explain the bill impacts the proposed distributed generation tariff and D1.12 have on residential DG customers?

A. Yes. To understand the actual bill impact of the proposed D1.12 on new solar customers, I conducted case analyses based on three actual residential solar customers who are served under the D1 rate schedule today, and followed the proposed service level estimation methods illustrated by Witness N.T.Foley. Supposing they are new solar customers who are required to take service under the proposed D1.12, I used their previous 12 months' hourly electricity use data to calculate what the actual annual electricity bill would be under the D1.12 rate schedule.

Based on their hourly inflow usage data of the previous twelve billing cycles, inclusive of the customer's current billing cycle, I estimated the average of the three highest inflow load use hours that occur on different calendar days to assign the customer to a service level on pre-defined thresholds (Witness N.F.Foley, Figure 3, page NTF-38). Then, I calculated the monthly capacity and distribution charges associated with the service level.

Table 3 displays the actual past 12-monthly electric usage a residential solar Customer D purchased from the grid, the total power outflow based on the monthly electricity bills, and the average top three hourly inflow loads over the same tperiod. Customer D's average top three hourly inflow load during the previous 12 billing cycles is 11.008 kW. Based on the assigned service level under D1.12, the monthly capacity charge is $64.37

and the distribution charge is $118.32. In response to discovery,[2] DTE confirmed that the monthly capacity and distribution charges are accurate based on the given average top three highest inflow use hours. DTE also confirmed that the monthly capacity charge and distribution charge would not change if the installation of a PV system doesn't reduce the average of their top three highest use hours over the previous 12 billing cycles, all else being equal.

Table 3: Comparison of Bill Impact on a Solar Customer under D1 vs. D1.12

Customer D: A Rider 18 customer with the D1 Residential service base schedule				**(1)**
Column (a)	Column (b)	Column (c)	Column (d)	(2)
Past 12-month electric usage from the grid (kWh)	6,169	Average top 3 hourly inflow load during the previous 12 billing cycles (kW)	11.008	(3)
Solar outflow kWh (previous 12 billing cycles)	8,404	Monthly capacity charge under D1.12	$64.37	(4)
Solar onsite consumption kWh	5,603*	Monthly distribution charge under D1.12	$118.32	(5)
Annual Electricity Bill Cost Estimation Breakdown by Scenarios	**Proposed D1**	**Proposed D1.12**	**No power outflow (under D1)****	(6)
Power Supply				(7)
Non-Capacity charge ($)	$300.94	$300.32	$300.94	(8)
Capacity charge ($)	$269.46	$772.44	$269.46	(9)
Distribution (does not include service charge)	$505.52	$1,419.84	$505.52	(10)

[2] *See* Exhibit AA-27, AAMDE-2 (first partial response).

Customer D: A Rider 18 customer with the D1 Residential service base schedule				(1)
Power Supply + Distribution Charge	$1,075.92	$2,492.60	$1,075.92	(11)=(8)+(9)+(10)
Additional Annual Capacity and Distribution Charge under D1.12	**$1,417.31**	**Monthly Excess Clean Electricity Disposal Fee=$118.11; Average clean energy disposal fee: $0.17/KWh=$1417.31/8404**		(12)=(9)c-(9)b+(10)c-(10)b
Average Cost of Coal Ash Disposal $/Ton (2022 projected cost)	$5.20***			(13)

*: Estimation. Assume 60% of solar generation is uploaded to the grid and 40% of generation is consumed onsite.
**: No power outflow means the customer chooses not to export excess power to the grid, ground the excess generation, and consumes the electricity generated by solar onsite without the use of an electric utility's transmission and distribution system.
***: Provided by Witness R. Lee (AAMDE-2.10)

For analysis purposes, I assume solar Customer D cannot reduce the average top three hourly inflow loads even if Customer D tries to do so, due to the inherent nature of solar generation and residential energy consumption behavior. Therefore, the monthly capacity charge and distribution charge for Customer D will most likely stay unchanged under the D1.12 rate schedule.

Suppose solar Customer D is a new solar customer under DTE's proposed definition.[3] Based on the proposed DG tariff, Customer D must take service under D1.12. Under the D1.12 rate schedule, Customer D has to pay more than $2,000 per year for the demand charge – which is about three times as much for a customer with an identical usage

[3] Witness N. Foley testimony, page 63, line 9: "At the later of either the Company hitting any of the category-specific reservations established through MCL 460.1173(3) or the first quarter of 2024,…At that time, all new Rider 18 resdiential customers will be required to take service under D1.12 and their DG installation, and Rider 18, must be associated with their D1.12 service."

pattern served under the D1 rate schedule.

Could Customer D become eligible to continue to take service under the D1 rate schedule, thus avoiding thousands in additional charges for the same usage? One alternative for doing so that Customer D has is just not to connect the PV system to the grid, meaning no excess electricity generated by the panels will outflow to the grid. Though Customer D cannot get any outflow credit from DTE, they should be able to continue taking service under the D1 rate schedule to avoid the excess fees or charges imposed by the proposed D1.12 rate schedule.

It is worth restating this result in simple terms: it will cost Customer D more than $100/mo to give DTE excess electricity for their grid compared to disposing of that electricity by putting it in the ground. This is the case even though the electrons can be immediately consumed by other users on the grid, and DTE will receive no cost reduction from the consumer of those electrons because they came from solar panels. Financially, therefore, DTE proposes to treat electrons generated from rooftop solar panels as something that costs $100/mo to take off its customers' hands. On a per kilowatt-hour basis, the additional capacity and distribution charges under the D1.12 are equivalent to charging $0.17/kWh to dispose of the excess clean electricity from Customer D.

Q. Why would the customer pay more to have DTE accept their extra electrons? Wouldn't they get paid an outflow credit?

A. DTE is proposing to determine the outflow credit by using the average monthly MISO hourly LMP and avoided line loss. Per Witness N.T.Foley's testimony, "For residential

18 customers on the secondary distribution system, …they would be compensated for 1.103 kWh of energy for every 1.000 kWh they outflow." The range of 2021 monthly average LMP at DECO.NEC is from $22.32/MWh to $57.37/MWh[4]. Therefore, the range of proposed outflow credit can be calculated as follows:

- Minimum outflow credit: $22.32x1.103/1000=$0.025/kWh;
- Maximum outflow credit: $57.37x1.103/1000=$0.063/kWh.

Therefore, even if Customer D gets compensated with the maximum outflow credit for every kW exported, they can get only $532 for exporting over 8,400 kWh clean energy to the grid while being forced to pay over $1,400 for "disposal". Thus, it would be a rational decision for new residential solar customers to choose not to connect their PV systems to the grid to avoid the energy "disposal" charge.

Q. If it would cost a customer money to have DTE accept their extra electrons, how much does that cost compare to DTE's estimated costs of disposing of other waste products?

A. The average coal ash disposal per ton at DTE's three permanent landfills is $5.20 per ton in 2022[5]. In other words, if this tariff accurately reflects costs, it costs DTE more to accept the excess electricity generated by a single residential customer's solar system than it does to safely dispose of 22 tons of toxic coal ash. The absurdity of this contention vividly illustrates that the D1.12 rate represents a penalty for those who chose to self-

[4] See Exhibit AA-28: AAMDE-2-13cc First Partial Discovery Response, provided by Witness A. Willis.

[5] See Exhibit AA-29: AAMDE-2.10 First Partial Discovery Response, provided by Witness R. Lee.

supply, not a meaningful evaluation of the cost of service associated with DG customers.

Q. Is Customer D unusual, such that other customers; usage patterns would not result in having to pay DTE significantly more to accept excess electrons from rooftop solar systems?

A. No. The bill impact on Customer D is not a random case. Exhibit AA-30 displays the actual bill impact on another two Rider 18 customers (Customers E and F) if taken service under the proposed D1.12 rate schedule. Their capacity and distribution charges more than doubled under the proposed D1.12 rate schedule.

Q. What key finding did you take away from this analysis?

A. The proposed D1.12 and distributed generation outflow credit estimation disproportionately allocate significantly more costs to new residential solar customers, which does not reflect the cost-alignment principle. It is improperly designed and penalizes solar customers.

Q. Why do you think the cost estimation structure of the proposed D1.12 is improperly designed?

A. The proposed D1.12 rate charges customers based on two key variables: 1) NCP demand, and 2) the average top three NCP demand estimated using the trailing 12-month billing cycles. This means even if a customer reduces the total electricity inflow demand from the grid and shifts peak-hour demand to off-peak hours, the customer cannot get any savings from capacity and distribution charges. On the other hand, some customers may get significant bill saving even though they are using more overall and adding more loads

to peak hours.

Though the supposed concept of the D1.12 rate schedule is to encourage customers to reduce their NCP load, the proposed fixed charge estimation method fails to incentivize staggering usage or avoid system peaks. Customers may end up paying more capacity and distribution charges under D1.12 than those served by the D1 rate schedule because they have higher NCP usage, even if the customer's highest usage never occurs during the system peak hours.

The Bitcoin mining vs. EV charging scenario analysis shows how the proposed D1.12 over incentivizes customers to stagger their usage to reduce their NCPs and add more demand to DTE's system-wide peak load while increasing the risk of substation transformer over-capacity.

The scenario analysis on charging an EV with a Level 2 charge shows a customer must pay an additional capacity and distribution charge that would be about 140% more than before having an EV and associated charger -- no matter when they charge the EV, for how many hours, and whether they smooth their load by carefully using other appliances at other times. Secondly, due to the high energy demand for EV charging, their top three NCPs are determined by the power demand of the EV charger.

The bill impact analysis based on Customer D's energy usage data shows a new solar customer would be significantly better off "dumping" all excess solar generation than exporting it to the grid. The additional energy capacity and distribution charges imposed by the proposed D1.12 make it cost much more for DTE to "dispose of" excess clean

energy from a single house's solar system than it does to dispose nearly 20 tons of coal ash. That is not a plausible application of cost-causation principles.

Q. Are the IT capital expenditure proposed in support of changes in the Rider 18 tariff reasonable?

A. No. DTE proposes to invest $0.4 million in projected test period capital in support of Rider 18 DG Pricing Updates (Witness A.M. Pizzuti, page AMP-24). Per DTE's response to discovery question MNSCDE-2.34, DTE paid a total of $0.2 million in outflow credits to Rider 18 customers in 2020. It is not a prudent use of money to build an IT system at a cost of double the annual amount of money it is built to track. But of course, the IT system costs to track the annual $0.2M expense are actually much higher. DTE already invested $0.8 million in 2020 to fund the system modifications necessary to bill customers on the Rider 18 DG tariff as approved in Case No. U-20162. That means DTE is proposing to spend a million dollars over three years on a system that tracks $200K of spending annually. This expenditure is not reasonable, especially given the Company's interest in changing the tariff conditions and calculations of outflow credits.

Q. What would be the consequence on all ratepayers if the Commission approves the proposed D1.12 rate schedule and changes in DG tariff?

A. The findings of bill impact analysis and scenario analysis for residential customers who chose to self-supply will pay much higher rates for power than customers who use more energy at more expensive times but do not elect to self-supply. I expect this will lead to a reduction in the number of customers exercising their right to self-supply. There would be several negative consequences on all ratepayers due to the rapid reduction of private

DG growth:

- ***Aggravate the substation overcapacity issue:***

Witness Pfeuffer indicates in her testimony that "at a 5% EV adoption, it's estimated that 40% of the Company's customers would be served a substation that is over capacity." Per DTE's response to discovery question AAMDE-3.20e, in DTE's territory, about 22% of customers are reserved by a substation that is over firm rating, over-capacity, or both. More DG customers could effectively alleviate the capacity constraints by exporting energy and reducing demand during summer peak hours. With the proposed D1.12 rate, the residential DG capacity growth will unequivocally slow down, causing over-capacity substations to need upgrades earlier than DTE planned thus adding more cost to ratepayers.

DTE conducted an impact analysis of Ann Arbor's EV Ordinances on the electricity system in 2020.[6] Engineers reviewed 25 proposed development sites in Ann Arbor for infrastructure impact from potential EV requirements. The evaluation shows 13 out of 25 sites could have required additional DTE upgrades ranging from $150K to $250K per site for 500kVA to greater than 750kVA additional capacity. The analysis also states: "as adoption of EV increases, it will be necessary to perform significant upgrades to the electrical system which could include the addition of new substations/circuits for increased capacity and the rebuild of existing, or installation of new poles/wires for

[6] Exhibit AA-33, Michael Witkowski, Impact of Proposed EV Ordinances to Electrical System, DTE, May, 2020

increased capacity and voltage support."

According to DTE's 2022 IRP, EVs are projected to be the fastest-growing end-use of energy for DTE. The estimated average annual growth of EV is 26.7%.[7] Following the projection, the EV penetration in Ann Arbor will reach 5% by 2025. According to DTE, this would result in 40% of substations in Ann Arbor overcapacity which would increase the risks of electric supply reliability (though the Company was unable to respond to discovery queries about how many Ann Arbor substations are already overloaded).

- ***Accelerating the need to redesign and rebuild the subtrasmission system:***

Witness S.G. Pfeuffer states in direct testimony (SGP-97, Q126, and Q127) that: "The current state of the Company's aging subtransmission system is not adequate to serve the customers' long-term needs given its limited capacity and reliability performance…The additional capacity provided by the subtransmission system redesign and rebuild would support and allow for additional capacity including new business expansion in the area with reduced construction time and cost to connect the new customers, as well as support load growth from existing customers including the continued adoption of EVs."

Three out of the six subtransmission priority criteria involve load overcapacity and growth (Table 14. Subtransmission Priority Criteria, provided by Witness S.G. Pefuffer, page SGP-99). The growth of residential DG capacity could mitigate the load growth and reduce the capacity constraints of the subtransmission system. Thus, ratepayers could

[7] https://dtecleanenergy.com/

save money due to the avoided and delayed substransmission system facility upgrades.

- ***Loss of ability to use existing capacity to offset projected shortfalls in MISO.***

The aggregated renewable generation capacity of private-owned DG systems is included in DTE's integrated resource planning (IRP)'s resource capacity, even while the Company proposes to make it more expensive to connect a residential system to the grid than to leave it isolated.[8] The growth of residential rooftop solar is factored in the load projection from 2022 to 2042, but given the incentives of the proposed tariff, it is unlikely that any of these systems would be connected to the grid, even if they are built. The failure to capitalize on privately-funded capacity investments would require ratepayers to pay for capacity if the utility was short, rather than take advantage of the self-supply assets to assist with grid reliability. That said, if the utility itself is not short, by effectively forcing out independently-owned capacity from distribution grid participation, DTE may be able to command higher prices from company-owned assets in the MISO market, especially in years where there is an overall shortfall, at the cost of increasing the risk of brownouts or grid failure for its customers.

- ***More non-capacity charge to ratepayers due to more running hours of peaking units***:

The highest cost units run at peak times. The growth of residential solar generation capacity reduces the system-wide demand during the system's peak hours (which tend to occur on hot, sunny days), thus resulting in fewer running hours of the highest-cost

[8] https://dtecleanenergy.com/

generation. Allowing a tariff structure that incentivizes grounding excess generation vs. exporting it to the grid will likely increase system-wide costs for energy. Therefore, the energy demand during peak hours will increase, which carries with it a number of both variable and capital costs to be borne by all ratepayers.

III. INSTALLING A ROOFTOP SOLAR VS. MIGREENPOWER SUBSCRIPTION

Q. Do DTE Electric's residential customers that wish to reduce their carbon footprint have other options to meet their goals beyond a residental solar installation?

A. Yes. A customer can voluntarily subscribe to the MIGreenPower (MIGP) program offered by DTE, or purchase carbon offsets on the open market.

Q. Why do some customers prefer to install PV systems more than subscribe to the MIGP program offered by DTE?

A. MIGP subscribers pay an additional charge to offset the fossil-fuel-generated electricity consumed through their monthly energy usage. The additional charge for clean energy from wind&solar mix is 2.7 cents/kWh and 1.9 cents/kWh for wind energy.[9] In my professional day-to-day work, I hear about two significant drawbacks. First, this is an offset program: a customer continues to pay the same amount to support coal plants (for instance) before and after signing up for the program. Second, the program is a perpetual charge, which means residential program subscribers will never get a payback for the investment in renewable energy through the MIGP program. In contrast to the MIGP

[9] https://newlook.dteenergy.com/wps/wcm/connect/dte-web/quicklinks/migreenpower

program, other Michigan utilities offer clean energy subscription programs that a customer can get the initial investment payback within 15 to 25 years. Please refer to Exhibit AA-34 for more information on the voluntary green programs offered by other Michigan utilities with this feature.

Investing in a PV system provides more benefits to customers who want to reduce their carbon footprint and clean the grid. For each dollar a customer invests in clean energy, installing a PV system on the rooftop reduces more carbon emissions than subscribing through the MIGP program, because it displaces instead of offsetting the use of fossil fuels for power generation. Customers can directly use the clean energy onsite and export the excess to the grid, which is most likely consumed by neighbors. In addition, the PV system can pay itself back within 13 years under the current inflow/outflow DG tariff. Finally, with the installation of the proper equipement (e.g. a transfer switch or an onsite battery), a customer may be able to use their solar panels to provide some power during an outage. As part of my job, I work with residents who weigh these considerations when making energy choices.

Q. Suppose the proposed D1.12 rate schedule and changes in DG tariff are approved, will customers who now prefer to install a PV system than subscribe to the MIGP program, change their decision? Please explain.

A. Yes. Assuming the approval of the proposed D1.12 rate schedule and DG tariff, customers considering installing solar and connecting their system to the grid will face a new reality, where generating excess power is a liability. The longer payback that results may make the MIGP subscription look like a more attractive option. Table 4 below

illustrates what the actual utility bill would be under different scenarios based on an actual non-solar residential customer: Customer G's previous 12 months' hourly use data.

As shown in Table 4 below, after installing a PV system, Customer G's electricity bill would be 33% more than before installing the system ($1,120 vs. $840 annually), though the customer uses 50% less electricity from the grid. If the customer chooses to subscribe to the MIGP program, the annual subscription cost would only be 12% more. Therefore, the customer has to pay about an additional $178 per year if they choose to install a PV system vs. choosing the MIGP subscription. The upfront cost plus the additional electricity bill charge under the new rate contribute to making self-supply unattractive.

Table 4: Cost Comparison of Installing Solar and Served by the D1.12 Rate Schedule vs. MIGreenPower Subscription and Served by the D1 Rate Schedule

Customer G Profile: A Non-Solar Residential Customer Takes Service Under D1		
Annual electricity usage kWh	4,901	(1)
Average top 3 hourly inflow load of the previous 12 billing cycles (kW)	5.192	(2)
Monthly capacity charge under D1.12	$29.26	(3)
Monthly distribution charge under D1.12	$53.78	(4)
No Solar under the D1 rate schedule		(5)
Power Supply from the Grid (kWh)	4,901	(6)
Non-Capacity charge ($)	$239.05	(7)
Capacity charge ($)	$199.03	(8)
Distribution (does not include service charge)	$401.55	(9)
Power Supply + Distribution Charge	**$839.63**	(10)=(7)+(8)+(9)
Install A Solar System Under The D1.12 Rate Schedule		(12)
Power Supply from the Grid (kWh) (assume 50% of supply from solar)	2,450	(13)
Non-Capacity charge ($)	$120.06	(14)=(7)/2
Capacity charge ($)	$351.12	(15)=(3)x12
Distribution (does not include service charge)	$645.36	(16)=(4)x12
Power Supply + Distribution Charge	**$1,116.54**	(17)=(14)+(15)+(16)

Customer G Profile: A Non-Solar Residential Customer Takes Service Under D1		
Annual Additional Capacity And Distribution Charge Under The D1.12 Vs. The D1 Rate Schedule	**$276.91**	(18)=(17)-(10)
No Solar under D1 with MIGreenPower Subscription		(19)
Power Supply from the Grid (kWh)	4,901	(20)
Wind&solar Rate Increase per kWh	$0.027	(21)
Percentage Of Energy Generation From Fossil Fuels	75%	(22)
Electricity Consumption Needs To Be Offset By Clean Energy Kwh	3,675	(23)=(2)x(22)
Annual MIGreenPower Charge to Offset Electricity Generation from Fossil Fuels	**$99.24**	(24)=(23)x(21)
Additional Cost: Install A Solar System vs. MIGreenPower Subscription	**$177.67**	(25)=(18)-(24)

Q. Suppose a customer chooses to install a PV system and take service under the proposed D1.12 rate schedule, in which they sell excess electricity to the grid. What is the most likely payback period for the PV system?

A. Taking the same non-solar Customer G as an example, Table 5 below shows that the customer will never have the system payback even under the most optimistic scenario. According to the proposed outflow credit calculation method, the most likely range of the outflow credit is between $0.025 to $0.063 per kWh based on the 2021 MISO LMPs provided by DTE.

- Minimum outflow credit: $22.32x1.103/1000=$0.025/kWh;
- Maximum outflow credit: $57.37x1.103/1000=$0.063/kWh.

Therefore, even if the customer gets compensated with the maximum outflow credit for every kW exported, the maximum amount they would receive for exporting 2,450 kWh to the grid is $155 – compared to an increase in their bill of $280 for the ability to sell those electrons to DTE.

Q. In the above scenario, what is the most likely payback period if the customer does not export excess solar generation to the grid?

A. Under this scenario, the most likely payback period for the solar system is 20 years, as shown in Table 5. The customer can continue to take service under the D1 rate schedule and enjoy savings from reducing using the power from the grid without paying additional charges for capacity and distribution. Therefore, installing a PV system that does not connect to the grid would be the most cost-effective option for a rational customer who wants to reduce carbon emissions.

Table 5: Estimation of Payback of Installing a PV System Served by the D1.12 Rate Schedule and Proposed Outflow Credit

Solar Payback Period Estimation (The Most Optimistic Scenario)		
Annual Solar Outflow kWh	2,450	(1)
Monthly Average LMP (maximum 2021 monthly average LMP) $/MWh	$57.37	(2)
Avoided line losses	10.30%	(3)
Outflow credit estimation (maximum monthly average LMP+Avoided line loss) $/kWh	$0.063	(4)=(2)x[1+(3)]
Total Annual Outflow Credit	$155.05	(5)=(4)x(1)
Additional Charge due to be required to take service under the D1.12 rate schedule (Table 4)	$276.91	(6)
Net credit from solar installation	($121.86)	(7)=(5)-(6)
Solar Generation Capacity (MW) (17% generation capacity)	3.4	(8)
Solar upfront cost ($2.5/Watt)	$8,391	(9)=(8)x2.5x1000
Minimum Payback period (year)	**None**	(10)
Don't Connect the PV System with the Grid and Ground Excess Power Generation		(11)
Avoided non-capacity charge ($)	$119.52	(12)
Avoided capacity charge ($)	$99.52	(13)
Avoided distribution charge ($)	$200.77	(14)
Total avoided supply and distribution charge	$419.82	(15)=(12)+(13)+14)
Solar Payback Period (year)	**20**	**(16)=(9)/(15)**

Q. If this tariff is adopted, would the effect to be to make self-supply of solar purchased

with customer dollars less attractive when compared to a subscription to the MIGreenPower program, which is funded with ratepayer dollars?

A. Yes. The proposed demand charge makes the residential PV system installation more expensive, so fewer customers could afford it. The proposed demand charge in capacity and distribution on new solar customers makes the MIGreenPower program much more competitive with the private solar market by eliminating the opportunity for payback of customer-funded systems if the excess power is used instead of disposed of, and by lengthening the payback period of self-supply systems by eliminating the opportunity to allow excess power to be placed on the grid. In addition to impeding the transition to carbon neutrality, the tariff would be detrimental to the Michigan residential solar industry as it will likely decrease installation businesses from residential customers.

Q. Are solar assets purchased through MIGreenPower cheaper than the electrons purchased from residential solar systems?

A. It is potentially more expensive than electrons purchased from DG customers. In Case No. U-20713 that DTE filed in 2020, for the Rider 17 (MIGreenPower Voluntary Green Pricing Program), DTE states the solar-only program would have a fixed subscription fee of $0.092/KWh, which is the combination of the LCOE of the solar assets ($0.09/kWh) and the marketing and administrative fee ($0.002/kWh). According to the proposed outflow credit calculation method, the most likely range of the outflow credit is between $0.025 to $0.063 per kWh based on the 2021 MISO LMPs provided by DTE. Assuming the excess energy from residential systems avoid system-wide energy delivery costs because those electrons are likely used by neighbors, and that DTE can claim capacity

credits for the systems that were funded with non-DTE dollars, then procuring energy from Rider 18 customers may be less expensive than investing ratepayer dollars in new assets.

Q. Are there other changes DTE proposes making that appear to be aimed at steering customers away from self-supply options and towards MIGP subscriptions?

A. Yes. Witness Sharma indicates that under Distributed Generation Enhancements: "Enhancement to the website will allow for existing customers to include MIGP Calculations in the bill impact calculator rooftop solar installation." Witness Sharma further explained the purpose of the calculator is to "allow customers who are interested in renewable energy programs to better understand the impact of adding solar to their home. The calculator will provide data related to the estimated financial and environmental impacts of installing rooftop solar." According to the results from the bill impact analysis using actual customer data illustrated before, such a calculator will likely show it costs more to install a PV system than a MIGP subscription, and that no payback is possible in either situation. Assuming the approval of the proposed D1.12 rate schedule and DG tariff, the bill impact calculator will effectively deter residential customers from installing a PV system and choosing to subscribe to the MIGP program.

It is also worth noting that currently, DTE has not offered such a calculator, as that would likely show that solar PV is actually a better financial investment than MIGP. The City of Ann Arbor offers assistance in making such calculations to customers, and believes the high percentage of customers electing to install such systems is partially attributable to the City's programs.

IV. ISSUES WITH SEPARATE METER PRODUCTS AND EV CHARGING PROGRAMS, AND THEIR IMPACT ON SOLAR CUSTOMERS

Q. Could a new EV plus solar customer have other pricing options to avoid the high costs of charging you illustrate above?

A. In theory, yes, but as a practical matter, no. One option for a solar customer to avoid extra high peak demand added to the whole home meter because of EV charging is to take service for the EV under rate schedule D1.9. It is an EV rate schedule that a customer can charge an EV overnight at a special time-of-use rate.

Q. Do you believe the D1.9 rate provides a practical option for customers who purchase an EV and want to fuel it with solar power from a rooftop system, while avoiding the costs that would result under the D1.12 tariff?

A. No, because the customer would have to have a very complicated and expensive system in place to charge the EV with solar. Per the DTE's response to discovery question AAMDE-2.12a, "the customer would not be able to attach their Rider 18 service to the separately metered service." Thus, in order to charge an EV with solar, while taking service under D1.9, you would need technology that would allow the system to connect to both the charger, which is on the residential meter, and the D1.9 meter. That is not possible, because most if not all centralized inverter architectures (e.g. SolarEdge) require a one-on-one relationship with a meter. In other words, you can't use a single SolarEdge inverter to offset two meters. As such, a solar customer can either choose to connect their solar to the whole meter (D1.12) or the EV charging meter (D1.9).

As a result of the DTE's proposed separate meter requirement for a DG customer to take

service under D1.9 to escape the high cost of power under D1.12, a solar customer cannot charge the EV with solar energy unless they have two chargers: one taking power from the meter attached to Rider 18 service, and the other taking service under the D1.9 meter. It takes about $1,400 to $2,000 to install a Level 2 charger, so this "solution" would require a sizable additional customer investment. Secondly, it may require upgrading the electrical panel capacity to be able to accommodate the power demand for two EV Level 2 chargers would be needed, which creates both a significant expense and likely delay in installation.

Thus, DTE's proposed tariffs would make EV adoption for customers that choose to self-supply more expensive. In this scenario, a solar customer must install two Level 2 chargers to avoid extra high peak demand and be able to charge the car with clean energy when they have plenty of solar generation. While this is theoretically possible, the technical, economic, and practical limitations mean it is extremely unlikely any customer would choose to do so.

Q. How many rate options offered by DTE require a separate meter?

A. Currently DTE offers four pricing options that require a separate meter:

- D1.9 Plug-in electric vehicle rate which provides reduced pricing during off-peak hours.
- D1.7 Geothermal rate offers a lower energy price during off-peak hours for geothermal systems.
- D1.1 CoolCurrents offers a lower energy price for central air conditioners or air source heat pump.
- Water heating service rate that provides a lower energy price by allowing DTE to

temporarily interrupt electricity to your water heater for up to four hours per day.

Q. Under DTE's tariff proposals, would customers who choose to self-supply with solar be able to take advantage of any of these rate options?

A. No. As I explained earlier in my remarks regarding EV charging, solar customers cannot use their PV system to power two meters due to the technical constraint of the inverters. Currently, Rider 18 customers are eligible to choose either to connect the PV system to a whole-home meter or a separate meter. The outflow credit varies among the whole-home meter (D1 or D1.2), the EV (D1.9), geothermal (D1.7), and interruptible AC rates (D1.1)[10]. It is a rational decision for a solar customer to choose is to connect the PV system with a whole-home meter, not a separate meter.

Not surprisingly, all residential DG customers chose to connect the solar system to the whole-home meter in 2020 per DTE's discovery response MNSCDE-2.34-01 R18 Outflow Credits by COS Class. Though DTE allows customers to connect their PV system to rate schedules that require a separate meter, no solar customer would choose that rate schedule for those reasons I discussed before. Therefore, solar customers are unable to utilize those price options requiring a separate meter. Secondly, the capital expenses to support the billing administration on those separate meter rate schedules for Rider 18 customers are wasted.

Per DTE's response to AAMDE-2.12a and 2.12b, DTE does not plan to eliminate the

[10] Witness A.Willis, Exhibit: A-16, Schedule F7, page 2 of 3, U-20836

separate meter requirement for Rider 18 customers in order to allow self-service customers to access these rate options.

Q. Is it necessary for DTE to require a separate meter for those special rate schedules, namely D1.9, D1.7 and D1.1?

A. No. The separate meter requirement should be eliminated as it creates additional unnecessary upfront costs to residential customers and requires more capital expenses for billing administration support. DTE does not need a separate meter to monitor and charge the power usage for those special rate schedules. The power demand for EV charging, geothermal, and air source heat pumps for heating and cooling requires 240v circuits. Besides EV charging and heat pumps, only limited household appliances need 240v circuits, namely electric dryers, electric ranges, and electric water heaters. DTE's real-time monitoring system can detect whether usage is for EV charging or running an electric dryer as the usage pattern is very different.

DTE's Bring Your Own Charger (BYOC) EV-Only Off-peak incentive pilot is a good example showing a separate meter is not needed to monitor the EV charging. It is a pilot program that doesn't require a separate meter as long as you own an EV and charge it with a 240v outlet. I called the customer service representative of BYOC and asked how they could tell if I use the 240v outlet for an electric cloth dryer or EV charging? The customer service representative confirmed that DTE's IT system can monitor the 240v circuit and detect if it is for EV charging or not.

Per Witness B.J.H Burns's direct testimony (page BJHB-22 and BJHB-33), "it took about

half the time for the Company's BYOC pilot to reach 400 participants as it did for the Residential Rebate element, and DTE saw a reduction of 21% in critical peak window load from BYOC participants' whole-home usage before and after enrollment."..."By offering BYOC, DTE increased Charging Forward participants from 615 to 1,050 at a relatively low cost within a year".

The success of the BYOC pilot shows the separate meter requirement does impede EV owners' participation in the EV rate schedule D1.9. The BYOC pilot effectively shifted the demand from peak to off-peak hours at a relatively low cost. Since a separate meter is not a tool DTE must have in ortotor, charge, and incentivize residential customers to shift the demand from peak hours to off-peak hours, it is a redundant requirement that adds more cost in this situation. DTE should provide options to residential customers who self-supply without installing a separate meter if the requirement of the meter does not affect DTE to monitor and charge participants.

Q. Does the separate meter requirement burden a particular set of customers more than others?

A. Yes. It uniquely burdens customers who choose to self-supply some of their own power needs from a residential solar system. It increases upfront costs to customers who want to adopt EVs and switch out fossil-fuel-burning appliances with energy-efficient electric ones. Based on the feedback from Ann Arbor residents, it takes about $1,000 or more to hire an electrician to install a separate meter. It takes years for a customer to get the meter installation cost back from the bill savings from the reduced rate schedules. Secondly, it makes electrification more expensive as a customer must install multiple meters for

different appliances. Each meter requires a fixed monthly service charge. For example, the monthly service charge for D1.9 is $1.95.

V. DATA ACCESS ISSUES

Q. What electric usage data does DTE provides to residential customers?

A. DTE provides the following electric usage data, based on my knowledge as a residential customer served by DTE for two and a half years:

- Energy usage report: A customer can generate an hourly energy usage report from the previous 13 months to monitor their data through the web service. The report is available in a downloaded spreadsheet.
- Electric Dashboard: An online tool that provides daily inflow energy use visualization with a time period ranging from yesterday to the previous 13 months. It does not provide a data download service.
- Monthly electric bill: A summary of total electric usage and billing information. For Rider 18 customers, it provides total outflow kWh and credit of the inclusive billing cycle.
- DTE Insight and Energy Bridge: Provides real-time electricity usage visualization showing either net power inflow or outflow through the App. It does not provide a data download service. Customers need to pay $1.99/month for the service.

Q. Does DTE provide solar generation data relating to the hourly generation, onsite hourly usage, and outflow data from the DTE website to Rider 18 customers?

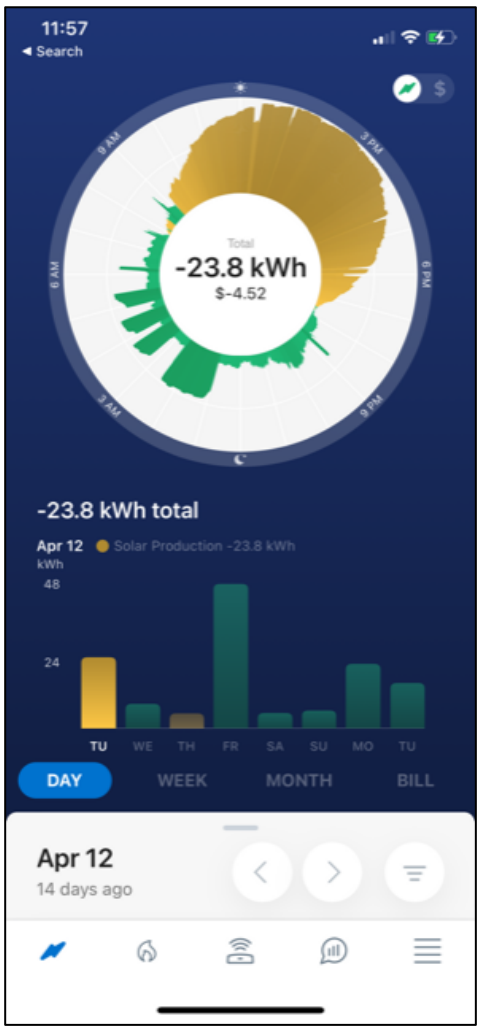
A. No. DTE does not provide solar generation, usage, and outflow data in the Energy Usage Report through the Company's web service.

Q. Does DTE collect the solar generation data relating to the hourly generation, onsite hourly usage, and outflow data from Rider 18 customers?

A. Yes. DTE reports monthly outflow kWhs and credits on electric bills. DTE's Insight App and Energy Bridge also provide real-time net energy usage visualization to program subscribers.

Q. Why it is important for Rider 18 customers to have access relating to solar generation, onsite hourly usage, and outflow data?

A. It helps a solar customer to better monitor their energy usage by combining solar data. It also helps a customer to estimate the financial and environmental impacts of installing rooftop solar, comparison of enrolling in different rate schedules, adjust energy usage behavior, etc. Though DTE collects the data and provides energy usage/export visualization to DG customers, the Company does not provide a data download service.



We got inquiries from residents who are frustrated by DTE's data access services and asked for help to figure out the solar generation, usage and outflow data. I have spent hours talking with DTE's web service and DTE Insight App representatives. They confirmed that a DG customer cannot download outflow data from either option.

This picture (right) is a screenshot of the net electricity usage visualization provided by the DTE Insight App. The green bar represents energy inflow and the yellow bar represents power outflow. If a solar customer wants to know how much solar generation is used onsite, and how much is exported to the grid, they have to manually write down the daily net inflow/outflow data from the data visualization tool (which they pay for) to estimate that. It is extremely time-consuming for a DG customer to collect the solar data manually. Providing the breakdown of solar generation and usage data via a data download service would greatly enhance solar customers to optimize their usage of the PV system.

Q. Does DTE's data service otherwise impede a customer from adjusting their energy consumption behavior?

A. Yes. DTE may eliminate a customer's energy usage data from the Energy Usage Report that is downloadable from the web services. Without the energy usage history data, a customer cannot evaluate the impact and savings due to energy conservation practices and behavior changes, etc. It is time-consuming for the customer to request help from DTE's customer representatives to retrieve the data. And even after expending that time, it may still be impossible for the customer to get their energy usage data.

I enrolled in the time-of-use program in January 2022 and installed a rooftop solar system in March 2022. I tried to download the previous 13 months' energy usage to compare the changes in energy demand and usage behavior before and after the rate plan change and solar installation. Surprisingly, I found DTE eliminated the energy usage data before January, 2022. I have called and emailed customer service multiple times and spent hours

telling them what happened and requesting the usage data without success. Two months passed since I notified them of the problem. I haven't gotten a follow-up from the DTE customer service regarding the data issue.

Q. Does this conclude your direct testimony?

A. Yes. However, I reserve the right to incorporate new information that may subsequently become available through outstanding discovery or otherwise.

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.

Fang Wu

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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-20836 ALJ Sharon Feldman

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DIRECT TESTIMONY OF JULIE ROTH

ON BEHALF OF

THE CITY OF ANN ARBOR

May 19, 2022

I. INTRODUCTION AND BACKGROUND

Q. Please state your name and business address.

A. My name is Julie Roth. My business address is 301 E Huron St, 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.

Q. Are you testifying today as an expert?

A. No. While I do have expertise in various aspects of energy, my testimony is based on personal knowledge gained in my work as an employee for the City of Ann Arbor, where I have day to day responsibilities that include analysis of energy options for residents.

Q. Please describe your educational background. and professional experience.

A. I have a BA from Kenyon College and a Master's degree from the University of Iowa. My relevant professional experience includes creation, implementation and management of programs to facilitate renewable energy, electrification and energy efficiency in our community, working with residents, contractors, non-profits, NGOs, and other governmental entities.

Q. Please describe your current role with the City of Ann Arbor.

A. I am a Senior Energy Analyst in the Office of Sustainability & Innovations.

Q. Please describe your duties in that role.

A. My duties include administration of the Solarize program, a distributed bulk-buy program to educate residents about on-site renewable energy and facilitate adoption with discounts

based on volume purchases with local solar contractors. In this role, I have worked with thousands of residents in Washtenaw County to help them understand the costs and benefits of solar and storage, as they determine whether to invest in distributed generation for their homes and small businesses. In addition, I am working on creating electrification and efficiency initiatives, as well as a commercial solarize program, and collaborating with colleagues on a number of A2ZERO programs, Ann Arbor's climate action plan.

Q. Have you previously testified before this Commission or in other proceedings?

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to give information regarding two studies DTE undertook regarding Distributed Generation participants in the DTE territory, and to speak to my experience working with Washtenaw County residents considering and purchasing solar.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit AA-37	AAMDE-1.1ai-01 DTE Solar and Battery Storage Screener
Exhibit AA-38	AAMDE-1.1ai-02 DTE Solar and Battery Storage Interview Guide
Exhibit AA-39	AAMDE-1.1ai-03 DG Study Screener IDIs topic guide
Exhibit AA-40	AAMDE-1.1avi-01 DTE PV and BESS Findings Summary
Exhibit AA-41	Discovery response AAMDE-1.1avii (with attachments)

II. DTE SURVEYS AND INTERVIEWS

Q. Have you reviewed the survey conducted by ICF on behalf of DTE (AAMDE-1.1ai-01 DTE Solar and Battery Storage Screener) and the associated Draft Interview Guide (AAMDE-1.1ai-02 DTE Solar and Battery Storage Interview Guide)?

A. Yes.

Q. Do you think this survey (the screener and the questions in the interview guide), was primarily designed to help DTE predict load? Why or why not?

A. No. This seems to be a survey mostly designed to elicit how to effectively compete with services offered by other businesses or entities, or potentially enter a new market.

Q. Do you think the interviews conducted were primarily designed to help DTE predict load? Why or why not?

A. No. Many of the interview questions seem to have little or no value for predicting the electrical load of DTE's system. Examples of such questions include:

- How did you go about finding a contractor for your solar project?
- Including the contractor you selected, how many contractors in total did you speak with before the contractor you used?
- What contractor did you use for your installation?
- Why did you select the contractor you used, compared to the others with whom you spoke?
- Did you purchase the solar project from the contractor, or did you sign a power purchase agreement or lease with the contractor or another firm that owns the system and to whom you make payments?

Q. What do you think these survey and interview questions were designed to do?

A. The nature of the questions suggests that DTE was interested in determining the ways consumers chose to explore alternative energy options offered in the commercial marketplace, and why they would choose a particular contractor. These are the type of questions I would expect from a business evaluating whether to enter a market or expand its services, and eliciting how to effectively compete with services offered by other businesses or entities. This is contrasted with a notable lack of questions regarding how individuals' electricity usage has changed, whether adoption of solar/storage has altered behavior in regards to energy usage and in what way, their exploration of alternative rate structures, or other question types directly related to predicting load from these customers.

Q. Have you reviewed the Findings Report (AAMDE-1.1avi-01 DTE PV and BESS Findings Summary)?

A. Yes.

Q. What are your observations of the Findings Report?

A. There was a notable absence in the Findings Report of anything related to anticipated PV market growth, battery uptake, or other factors relevant to load forecasting. Moreover, the report DTE received from the contractor had many pages regarding customer attitudes toward private contractors and no pages regarding any substantive evaluation of load shifting, behavioral changes due to solar / storage, or other factors related to load predictions. One of the 5 Research Questions being asked is "Were there certain value propositions from the sellers of PV and BESS that were especially compelling?" This, combined with a considerable amount of data regarding how customers found and chose

installers, what arguments were compelling for batteries, and what events or factors prompted movement from learning to sales (e.g. the Solarize program), support a much different underlying reason for the study than the reason given by DTE in discovery.

Q. Were ratepayer dollars used to fund the survey and interviews?

A. Yes. DTE stated in discovery response AAMDE-1.1avii that $39,000 of ratepayer dollars were used to fund the survey.

Q. Do you think it is appropriate to recover the costs of this survey and interview effort from ratepayers?

A. No. DTE should not be able to make ratepayers pay for it to use information it can access because of its monopoly position to ask specific distributed generation customers about their current commercial relationships with private businesses they have picked to help them generate some of their own electricity.

Q. Do you think this survey was primarily designed to help DTE assess the potential for competing with other providers of energy services? Why or why not?

A. Yes. As stated above, many interview questions suggest motives other than load forecasting, including assessing the potential for competition with other energy service providers.

Q. Have you reviewed the DTE Distributed Generation Study Topic Guide (AAMDE-1.1ai-03 DG Study Screener IDIs topic guide)?

A. Yes.

Q. Do you think this topic guide was designed to help improve the customer experience regarding the DG program? Why or why not?

A. No. A considerable amount of time in this interview was spent on customer decision-making processes, their choices about the systems they installed, and even how they would feel about DTE entering the market. There is no relationship between these topics, and customer satisfaction with DTE's DG program. Examples of such questions:

- What sources did you use to get comfortable with your decision as well as choose a panel company and installer?
- If you talked to multiple sources, how did you choose the winner?
- What information did you learn that was most influential to your decision? Who provided it?
- Ultimately, what were you hoping to accomplish by adding solar to your house? In other words, if I asked you to explain all the ways you hoped life would be better if you had solar, what would you include in that list?
- Of all the items, which were probably most important to you?(explore green, escaping high DTE bills, off the grid, etc.)
- Instead of adding solar, did you consider any other ways of meeting at least some of these goals (for example, MI Green Power as a way to reduce carbon footprint)?
- Before we discuss the actual installation process, let's start with what you bought and how that set-up is working out for you.
- Can you describe your set-up to me in terms of brands, size, generating power, battery storage, etc.?

- If you had it to do over again, would you? Would you change anything about what you bought or installed? Or who installed it? Tell me about that.

Additionally, there were explicit questions asked about the potential of DTE entering the market:

- If you had had the option to choose DTE as the provider and installer of solar panels, would you have considered using DTE instead?
- If so, what would the potential advantage for you be?
- If not, why would you probably shy away from DTE as the installation partner?

Q. Have you reviewed the DTE Distributed Generation In Depth Interviews Final Report? What are your observations regarding it?

A. Yes. The most compelling conclusions reached in the final report around the purported goal of "improving the customer experience" indicate that the previous rate changes from Rider 16 to Rider 18 were seriously problematic for people, including a "sense of betrayal" from DTE, whom they "no longer see as a true partner." Given those conclusions, and the fact that DTE is now proposing a rate structure that would even more drastically disincentivize solar adoption and increase costs to solar users, I do not believe that DTE is being honest in their claim that the purpose of the study was to solicit feedback on how to improve the program for customers. Following up with several pages evaluating residents' feelings about DTE entering the business of installing solar further adds to my skepticism regarding DTE's purported intent, and points to market research and setting themselves up to compete with other businesses.

III. PROPOSED CHANGES TO DISTRIBUTED GENERATION AND SOLARIZE PROGRAM

Q. What do you believe the proposed tariff would do if it were put into place?

A. I believe the proposed tariff would essentially terminate the Solarize program (and the vast majority of home and small business installations throughout the DTE territory), because it would treat their contributions to the grid as a burden instead of a benefit. Individuals willing to invest money in generating clean energy for their homes would not only have no financial pay-back to their investments, but actually increase their energy costs. Furthermore, I anticipate a significant loss of jobs, increase in unemployment, and small businesses closing as the robust solar industry in Southeast Michigan would no longer be able to compete and thrive.

Q. In your experience working with Solarize participants, what are the reasons people give for considering solar?

A. People express their desire to help reduce fossil fuel usage to help further the transition to clean energy given the climate crisis; their willingness to invest money up-front, knowing that their energy costs will be more predictable over time given DTE's dramatic rate increases; their desire to "pay it forward" and help create a livable world for their children and grandchildren; their desire to be more self-reliant in their energy production due to lack of confidence in DTE and the current grid; their overall dissatisfaction with DTE; and very frequently, their desire to weather grid outages with solar plus storage given the frequent outages they have experienced in the past several years. The fact that their solar investment would generally pay itself off in around a decade, plus or minus a couple years, enable many people to make this decision. For others, however, the change from net metering

(Rider 16) which resulted in a much longer pay-back period meant they could no longer afford the upfront costs, making solar a less attractive and equitable solution than it was prior to adoption of Rider 18, and many people express anger about this.

Q. Do these reasons align with those noted in the Emicity Report?

A. Largely yes. However, I also hear a great many frustrations with DTE overall, and with frequent outages. While the Report characterizes people with concerns about reliability as "preppers," that is not consistent with my experience and discussions with residents; they are more typically residents who are frustrated by poor reliability.

Q. If the proposed tariff were adopted, what do you anticipate the affect to be on these residents' ability to participate in distributed generation?

A. I expect that only the very wealthiest individuals, motivated by resilience and reliability issues and climate change, will be able to access distributed generation. The financial burden that would be placed on residents would not just extend the pay-back time for the investment, but eliminate it, and actually add additional costs. Very few people are in the position to take this financial hit. This is an enormous equity issue.

Q. In your role coordinating Solarize, do you work with solar installers?

A. Yes, I work closely with local and regional solar installers on a weekly basis.

Q. Have you heard from installers their thoughts about how the proposed tariff would affect their businesses?

A. Yes. There is near-universal concern that installers would need to lay off workers, shift business models to maintenance of solar only, and for a good number of them, close

entirely. These are small businesses who have invested their work in the Southeast Michigan area, creating skilled jobs, workforce development and apprenticeship programs. All of this would be lost, at great harm to those workers as well as to the states' efforts to expand our green energy workforce and economy, not contract it.

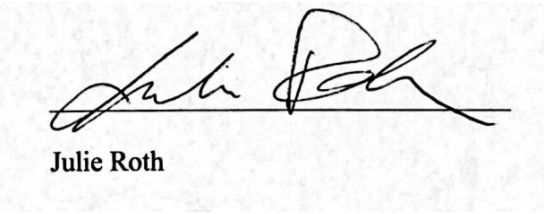
Q. Does this conclude your direct testimony?

A. Yes. However, I reserve the right to incorporate new information that may subsequently become available through outstanding discovery or otherwise.

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.

I certify that the above testimony is true.



Julie Roth