### STATE OF MICHIGAN

# BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)
DTE ELECTRIC COMPANY	)
for authority to increase its rates, amend	)
its rate schedules and rules governing the	)
distribution and supply of electric energy, and	)
for miscellaneous accounting authority.	)

Case No. U-21297

### QUALIFICATIONS

#### AND

#### DIRECT TESTIMONY

OF

#### ADELLA F. CROZIER

# DTE ELECTRIC COMPANY QUALIFICATIONS AND DIRECT TESTIMONY OF ADELLA F. CROZIER

Line <u>No.</u>

101		
1	Q1.	What is your name, business address and by whom are you employed?
2	A1.	My name is Adella F. Crozier (she/her/hers). My business address is One Energy
3		Plaza, Detroit, MI 48226. I am employed by DTE Energy Corporate Services LLC,
4		a subsidiary of DTE Energy Company (DTE Energy), within Regulatory Affairs as
5		a Director.
6		
7	Q2.	On whose behalf are you testifying?
8	A2.	I am testifying on behalf of DTE Electric Company (DTE Electric or Company).
9		
10	Q3.	What is your educational background?
11	A3.	I received a Bachelor of Science degree in Metallurgical Engineering from Iowa
12		State University and a Master of Business Administration degree from the
13		University of Chicago. I have also completed several Company sponsored courses
14		and attended various seminars to further my professional development.
15		
16	Q4.	What is your work experience?
17	A4.	Prior to my employment at DTE Energy, I was employed by LTV Steel Company
18		(LTV) in various roles including Metallurgical and Quality Control Engineer in
19		positions of increasing responsibility for different product lines. My last role with
20		LTV was as Product Manager in the Sales and Marketing Department. In this role,
21		I had responsibility for managing the relationship between the Sales and Marketing
22		Department and one of LTV's major production plants. As part of my
23		responsibilities, I ran financial and engineering analyses related to product line
24		offerings.
25		

<u>No.</u>	
1	I joined DTE Energy in 2003 as a Technological Specialist in the Fossil Generation
2	Department's Engineering Support Organization. In 2004, I was promoted to
3	Supervisor – Mechanics and Metallurgy. In 2005, I joined the Regulatory Affairs
4	Department as Manager of Special Projects. In this role, I assisted the
5	Environmental Affairs Department with their portions of Detroit Edison's general
6	rate case filings and served as a member of several workgroups related to Governor
7	Granholm's 21st Century Energy Plan and Capacity Need Forum. I helped with
8	the Company's implementation of Michigan's 2008 energy legislation, particularly
9	those areas related to energy optimization. I managed several Detroit Edison
10	energy optimization filings as well as provided witness testimony regarding the
11	revenue requirement of several energy optimization plans and reconciliations.
12	During this time, I also assisted the case managers of general rate cases.
13	
14	I was promoted to Manager of Electric Regulatory Strategy in 2013 where my
15	responsibilities included research of regulatory matters and my team also provided
16	management of DTE Electric's general rate cases.
17	
18	I was promoted to Director within Regulatory Affairs in 2016. In this role, I was

18 I was promoted to Director within Regulatory Affairs in 2016. In this role, I was 19 responsible for managing the Company's activities at the Michigan Public Service 20 Commission (MPSC or Commission) and at the Federal Energy Regulatory 21 Commission (FERC). Members of my team that work on State activities provided 22 case management for some of the Company's compliance filings, research 23 activities pertinent to our electric utility, and coordinated activities related to the 24 state's 2016 energy legislation.

25

Line

Line <u>No.</u>			U-21297
1	Q5.	What are yo	ur current duties and responsibilities?
2	A5.	I remain a	Director within DTE Energy's Regulatory Affairs Department.
3		Currently, in	this role, my team is responsible for managing the Company's state
4		filings and a	activities at the Michigan Public Service Commission (MPSC or
5		Commission	). Members of my team also provide various research activities
6		pertinent to c	our electric utility and provide cost of service and revenue requirement
7		modeling.	
8			
9	Q6.	Have you pr	eviously sponsored testimony before the Michigan Public Service
10		Commission	(MPSC or Commission)?
11	A6.	Yes. I spons	ored testimony in the following DTE Electric cases:
12		U-15806	Detroit Edison's Energy Optimization (EO) Plan
13		U-15806 A	Detroit Edison's EO Amended Plan
14		U-16358	Detroit Edison's 2009 EO Reconciliation
15		U-16359	Detroit Edison's 2010 EO Reconciliation
16		U-16737	Detroit Edison's 2011 EO Reconciliation
17		U-20561	DTE Electric 2019 Rate Case
18		U-18232	DTE Electric 2020 Renewable Energy Plan (REP) Amendment
19		U-18091	DTE Electric 2021 PURPA Avoided Costs
20		U-20836	DTE Electric 2022 Rate Case
21		U-21193	DTE Electric 2022 Integrated Resource Plan (IRP)
22			

A. CROZIER

T in

# 1 **Purpose of Testimony**

2	Q7.	What is the purpose of your testimony in this proceeding?
3	A7.	The purpose of my testimony is to:
4		• Provide an overview of the Company's entire general electric rate case
5		including a summary of the drivers for filing this case at this time, and the
6		amount of the Company's projected revenue deficiency starting December
7		1, 2023;
8		• Review the overall methodology used to develop the Company's projected
9		test year amounts in this case;
10		• Address the following ratemaking and policy considerations which are
11		included in my testimony, propose unique or different ratemaking
12		treatments, respond to prior Commission orders, highlight noteworthy
13		regulatory issues, or address topics of interest expressed by stakeholders:
14		• The Company's future securitization of costs associated with the
15		Company's tree trimming surge;
16		• Corporate memberships and costs included for ratemaking as ordered in
17		the Company's last general rate case, U-20836;
18		• The Company's recently approved MIGreenPower program contract
19		with Ford Motor Company (Ford) as required by the Commission in its
20		December 21, 2022 Order in Case No. U-21285; and
21		• Introduce the Company's other witnesses.
22		
23	Q8.	Are you sponsoring any exhibits in this proceeding?
24	A8.	Yes. I am supporting the following exhibit:
25		Exhibit Schedule Description

Line <u>No.</u>

<b>.</b> .		A. CROZIER
Line <u>No.</u>		U-21297
1		A-27 Q1 Corporate Memberships
2		
3	Q9.	Was this exhibit prepared by you or under your direction?
4	A9.	Yes, it was.
5		
6	Case	Dverview
7	Q10.	Can you briefly describe DTE Electric?
8	A10.	Yes. DTE Electric generates, purchases, distributes, and sells electricity to
9		approximately 2.3 million customers in Southeast Michigan. The Company has
10		over 11,000 megawatts of generation capacity including, coal, wind, solar, nuclear,
11		hydroelectric pumped storage, and natural gas. DTE Electric delivers electricity to
12		its customers over approximately 31,000 miles of overhead distribution lines and
13		over 16,000 miles of underground distribution lines across a service territory that
14		encompasses 7,600 square miles. Founded in 1903, DTE Electric is the largest
15		electric utility in Michigan and one of the largest in the nation.
16		
17	Q11.	What is DTE Electric's overall business objective?
18	A11.	DTE Electric's overall business objective is to provide safe, reliable, clean, and
19		cost-effective electric service to its customers and deliver reasonable and
20		appropriate compensatory returns to DTE Energy shareholders while maintaining
21		the Company's financial health. Providing safe, reliable, clean, and cost-effective
22		service to its customers means that DTE Electric: 1) provides quality customer
23		service, 2) operates its system safely, and 3) delivers electric service reliably at a
24		reasonable cost while protecting the environment.
25		

# Q12. How do the requests in this general rate case filing support DTE Electric's overall business objectives?

3 A12. This rate case represents a major commitment to reliability and innovation. The 4 Company is seeking approval of significant infrastructure investments to improve 5 the reliability and resilience of its electric distribution system as detailed in its 2021 6 Distribution Grid Plan filed in Case No. U-20147. This involves redesigning, 7 hardening, and rebuilding antiquated infrastructure, modernizing how the electric 8 grid is monitored and operated, and performing preventive and proactive 9 maintenance and tree trimming at standards that reflect today's operating 10 conditions, including security risks and more extreme weather. These investments 11 will not only reduce how often and how long customers experience power outages 12 but will also enable the Company to support greater optionality for customers in 13 adopting technologies such as batteries, solar, and electric vehicles (EVs).

14

15 To support innovation during this period of transformational change in the energy 16 industry, the Company is also proposing new technology deployments, including 17 enhanced information technology capabilities to reduce costs and improve the 18 customer experience; energy storage in the form of batteries; non-wires 19 alternatives; and expanded programs to support deployment of EVs. The 20 Company's generation fleet continues to evolve towards cleaner resources with 21 new renewable energy facilities and the successful start of commercial operations 22 at Blue Water Energy Center (BWEC) in the second quarter of 2022. DTE Electric 23 has retired six of its coal-fired facilities, which accounts for all of its Tier 2 coal 24 units (Marysville, Harbor Beach, Conners Creek, River Rouge, St. Clair, and 25 Trenton Channel) and recently filed an IRP (Case No. U-21193) outlining a proposed course of action that will scale up the development of renewable energy
 and battery storage while seeking to accelerate the retirement of its remaining two
 coal-fired facilities, Belle River and Monroe.

4

5

#### Q13. Why has DTE Electric filed this general rate case at this time?

6 A13. As discussed above, DTE Electric is implementing a major capital investment 7 program to improve reliability and resilience, most notably for the distribution 8 system. However, the Company's existing rates and projected electricity sales 9 cannot sustain this level of infrastructure investment without a rate increase. The 10 only way that DTE Electric can adequately provide the required service levels that 11 our customers desire and deserve is by being financially healthy. The Company's 12 current authorized rates are not expected to provide DTE Electric with adequate 13 revenues to make necessary infrastructure investments while providing a 14 reasonable opportunity to earn a fair return on equity beginning in December 2023.

15

#### 16 Q14. What are the measures used to determine the Company's financial health?

17 A14. Maintaining DTE Electric's financial health requires that the Company has a 18 reasonable opportunity to earn its cost of capital, that the Company has a well-19 balanced capitalization (no less than 50% equity to total permanent capitalization), 20 and that the Company is able to maintain its A/Aa3/A+ credit ratings for senior 21 secured debt from the three major rating agencies. These preconditions are 22 necessary to ensure DTE Electric has full access to capital markets at reasonable 23 rates, terms and conditions regardless of business cycle timing or industry 24 conditions. As discussed by Company Witness Lepczyk, without full access to

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capital markets at reasonable terms and conditions, the cost of providing utility services can increase significantly.

3

#### 4 Q15. Why is the Company's financial health important for customers?

5 A15. To attract the capital necessary for the prudent operation and maintenance of its 6 facilities, the Company must be able to demonstrate its ongoing financial health. 7 Inadequate rates will ultimately result in higher financing costs and have a 8 significant negative impact on the ability to adequately serve our customers and 9 maintain the integrity of the Company's electric distribution and generation assets. 10 This negative impact will occur because greater expenditures would be required to 11 support financing costs, and therefore, would not be available for system 12 maintenance or customer service. Similarly, inadequate funding for capital and 13 maintenance programs, over time, would result in the deterioration of DTE 14 Electric's generation and distribution infrastructure, ultimately resulting in reduced 15 system reliability and service quality.

16

Thus, it is essential to DTE Electric's financial health that the ultimate cost that customers are asked to pay for the Company's services generate sufficient cash flow from operations to fund the necessary capital expenditures to maintain and improve service as well as pay a reasonable dividend.

21

Q16. How does DTE Electric's continued implementation of infrastructure
 maintenance and investment programs provide additional benefits to
 customers and the region?

1 A16. DTE Electric has an important positive economic impact on the communities it 2 serves. DTE Electric is one of the largest employers in Southeast Michigan with 3 over 4,800 employees. Through the Pure Michigan Business Connect campaign, 4 the Company utilizes the services of numerous local contractors and vendors. DTE 5 Energy spent over \$2 billion with Michigan based companies in both 2021 and 6 2022. Through property taxes, DTE Electric contributes to the financial health of 7 local communities. In the historical test year, DTE Electric paid approximately 8 \$280 million in property taxes to Michigan communities. To maintain facilities, 9 comply with various regulations, implement its Distribution Grid Plan, and 10 continue the transformation of its generation fleet, DTE Electric continues to make 11 major capital investments in the communities in which it operates. Thus, DTE 12 Electric supports additional job growth opportunities and provides continuing and 13 incremental tax revenue for our local communities.

14

# Q17. Does DTE Electric provide assistance to customers who have trouble paying their utility bill or provide opportunities to customers needing assistance to participate in some of the Company's offerings?

18 A17. Yes. The Company has programs to help customers who are having trouble paying 19 their utility bill as well as offerings that help low-income customers participate in 20 some of the Company's other program offerings. For example, DTE Electric works 21 to help customers maintain service and reduce arrears and also offers residential 22 income assistance (RIA) and Low-income assistance (LIA) credits to help vulnerable customers manage utility bills. These are discussed by Witness Johnson 23 24 along with details regarding a percentage of income payment plan pilot the 25 Company launched in the first quarter of 2022. Additionally, Witness Peterson

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1		discusses our electric vehicle program which helps low-income customers. Lastly,
2		any customer taking service under the Company's MIGreenPower (Rider 17) tariff,
3		as well as any other interested parties, can support a low-income donation pilot on
4		a monthly basis or as a one-time contribution. These voluntary contributions
5		provide fully subsidized subscriptions to low-income customers who are eligible to
6		participate.
7		
8	<u>Requ</u>	ested Relief
9	Q18.	What rate relief was approved in the Commission's Order in the Company's
10		last rate case, Case No. U-20836?
11	A18.	The Company's last general rate case, Case No. U-20836, was filed in January 2022
12		requesting \$388 million in rate relief. In the Commission's November 18, 2022
13		Order, DTE Electric received approval for \$31 million in rate relief.
14		
15	Q19.	How would you characterize the state of the Company's general electric rates?
16	A19.	DTE Electric has voluntarily taken meaningful actions to mitigate the level of the
17		Company's general electric rates during the COVID-19 pandemic. The Company
18		made three separate accounting requests <sup>1</sup> from June 2020 through February 2021
19		that assisted the Company and its customers in managing costs through an
20		unprecedented period. The Company held off on filing a rate case for more than 2
21		years. As we return to more ordinary circumstances and look to the future, the
22		modest increase in rates approved in Case No. U-20836 is insufficient to maintain
23		positive momentum on necessary infrastructure improvements and meet changing

<sup>&</sup>lt;sup>1</sup> Case No. U-20835 filed on June 9, 2020 and approved on July 9, 2020; Case No. U-20921 filed on October 26, 2020 and approved on December 9, 2020; and Case No U-20835 filed on February 26, 2021 and approved on April 8, 2021.

electric service expectations. The level of investments undertaken by the Company
 since 2021 and projected to be spent through the projected test year in this case
 requires the Company to present this filing.

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#### 5 Q20. What rate relief is DTE Electric requesting in this case?

6 A20. As calculated by Company Witness Vangilder, DTE Electric expects a revenue 7 shortfall of \$618.5 million for the December 1, 2023 through November 30, 2024 8 projected test year. This deficiency assumes that the Company's proposed 9 infrastructure recovery mechanism (IRM) is approved. Witness Foley discusses 10 the rationale for the IRM in his testimony. Should the IRM not be approved, the 11 Company's shortfall would be \$621.9 million for the December 1, 2023 through 12 November 30, 2024 projected test year. As supported by various Company 13 witnesses, factors contributing to this shortfall are the revenue requirement 14 associated with increased investments made in plant and the associated depreciation 15 and property tax increases, a sales decline from the level included in current rates, 16 and the impact of inflation and its impact on DTE Electric's O&M and borrowing 17 costs.

18

# Q21. Can you highlight some of the major investments and expenses included in the Company's request for rate relief?

A21. This rate case sets forth the rationale, spending, timing, and expected customer
 benefits associated with significant investments in distribution, generation, and
 customer service. Several programs to highlight are summarized below.

Strategic infrastructure investments in substations, poles, wires,
 transformers and other electric distribution assets to modernize equipment,

1		support growth in customer demand in specific areas, improve worker and
2		public safety, and reduce the frequency and duration of power outages. This
3		also includes plans to accelerate the conversion of the 4.8 kV system to a
4		higher voltage, expanding the pole top maintenance program, and increased
5		investment in distribution automation and telecommunications
6		technologies.
7	•	Continuation of the multi-year tree trimming "surge" program that reduces
8		outages on circuits trimmed to the new, more protective standard. The
9		continuation of the Commission-approved tree trimming program
10		combined with the recent \$90 million contribution <sup>2</sup> by DTE Electric (an
11		amount that is not included in this rate case), will bring the Company closer
12		to completion of the surge which is expected in 2025. This program remains
13		critical to improving reliability and resilience across the system and will be
14		foundational to the Company's overall efforts to improve reliability.
15	•	Plant removal associated with the retirement and decommissioning of
16		power generation assets at Harbor Beach, Conners Creek, River Rouge, St.
17		Clair, and Trenton Channel Power Plants. With the Company's final Tier
18		2 plants retiring in 2022, DTE Electric is committed to the removal of these
19		retired steam generating units. The process involves three primary
20		activities, namely decommissioning, decontamination, and demolition.
21		Witness Morren addresses this project in detail in his testimony.
22		
23	Q22. What	t investments is the Company making to promote greater levels of

# 24

Q22. What investments is the Company making to promote greater levels of advanced technology across its businesses?

<sup>&</sup>lt;sup>2</sup> U-21128 filed August 31, 2021 with Commission order issued November 4, 2021.

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A22. The Company is working to deploy advanced technologies in all areas of its
 business as well as furthering its commitment to deploy proven technology to
 improve our customers' experience with DTE Electric's services. Examples are
 briefly described below:

- 5 Energy storage projects proposed for the Energy Supply portfolio include 6 two grid-scale battery applications. One is the continuation of the 14 MW 7 Slocum battery pilot project slated to replace retiring peaking generation 8 located in Trenton, Michigan. The other project, also located in the City of 9 Trenton, is a 106 MW battery that is consistent with the build plan included 10 in the Company's 2022 IRP planned course of action. This project will be 11 located at the site of the recently retired Trenton Channel Power Plant. 12 Witness Morren addresses this project in detail in his testimony.
- Distribution Operations also continues to evaluate different use cases for
   energy storage. Examples include the use of batteries to help relieve certain
   substation overloads and a battery trailer which can be sited in place of
   traditional portable generators. Witness Hill addresses these projects in
   detail in his testimony.
- With the success and momentum of the current Charging Forward and eFleets pilots and recent Commission approvals in Order No. U-20836, the Company is beginning to transition to permanent programs or proposing extended or new pilot elements. Establishing various pilots, incentives, and ownership models will allow DTE Electric to best support customers as they increasingly adopt EVs. Witness Peterson addresses this effort in detail in her testimony.

1 As outlined in the Company's information technology (IT) plans, the 2 customer IT portfolio of investments prioritizes the enhancement of 3 customer experiences and operational efficiencies with respect to movein/move-out, billing, payment, collection, and outages. The plans also 4 5 outline how significantly higher levels of IT investments are being made to 6 not only support and maintain the Company's IT infrastructure by updating 7 the current core systems that are critical to operations, but also to advance 8 and enhance new capabilities. Witness Hatsios addresses these customer 9 service IT plans in detail in his testimony.

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#### 11 Rate Case Methodology

# Q23. Can you describe the methodology the Company is using to support its projected test year positions and its recommendations in this case?

14 A23. Yes. DTE Electric has used actual historical data as the point of departure for most 15 estimated cost levels for the projected test year. These historical costs were then 16 adjusted for the impact of inflation. As has been DTE Electric's practice in prior 17 rate cases, certain other costs reflect specific estimates or projections where general 18 impacts of inflation alone would be insufficient to capture known changes. For 19 example, some of these include, but are not limited to, capital expenditures for new 20 plant and uncollectible expense. All these cost components and the circumstances 21 involved are explained and supported by other Company witnesses.

22

# Q24. What historical and projected test year periods are being used by DTE Electric for purposes of calculating its projected revenue deficiency?

110.		
1	A24.	The historical test year used by DTE Electric is the calendar year ended December
2		31, 2021. This 12-month period was then normalized and adjusted for known and
3		measurable changes, as supported by the Company's witnesses in this case, to
4		arrive at the Company's December 1, 2023 through November 30, 2024 projected
5		test year. As this case is being filed in early 2023, the Company has included 11
6		months (January - November) of actual capital investments in the 2022 bridge
7		period.
8		
9	Q25.	Are there any additional recovery mechanisms being requested in this rate
10		case?
11	A25.	Yes. The Company, through the testimony of Witness Foley, is proposing an
12		investment recovery mechanism (IRM). This mechanism will be focused on certain
13		strategic capital programs related to customer safety and reliability within the
14		Company's Distribution Operations' investments. Witness Foley describes the
15		mechanism in detail including program execution metrics and other features to
16		drive accountability and transparency in the IRM's implementation. Witness Foley
17		also addresses the relationship between the proposed IRM with this and future
18		general rate cases. The underlying investments to which the IRM applies are
19		supported by Witnesses Deol, Elliott Andahazy, and Hill.
20		
21	Tree	<u>Irimming Surge</u>
22	Q26.	Has the Commission previously approved tree trim "surge" funding in the
23		Company's recent rate cases?
24	A26.	Yes. In the Company's three most recent general electric rate cases (Case No. U-
25		20162, Case No. U-20561, and Case No. U-20836), the Commission approved the
26		deferral of "surge" amounts for the Company's tree trimming program. These

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1		"surge" amounts represent an increase in annual funding above the baseline tree
2		trimming O&M and have been supporting the Company's goal of achieving a five-
3		year trim cycle for its distribution system.
4		
5		The Commission approved \$67.0 million and \$52.7 million in surge funding for the
6		years 2023 and 2024, respectively in the Company's most recent general rate case,
7		U-20836. As discussed in detail by Company Witness Ms. Hartwick, this "surge"
8		in tree trimming spending was established to occur over an approximately seven-
9		year period ( $2019 - 2025$ ). At the program's termination, the Company expects to
10		maintain all circuits on-cycle to the enhanced tree trimming specification, as
11		discussed by Witness Hartwick.
12		
13	Q27.	Is the Company requesting that the Commission approve a surge deferral for
13 14	Q27.	Is the Company requesting that the Commission approve a surge deferral for 2025 which is the seventh and last year of the program?
13 14 15	<b>Q27.</b> A27.	Is the Company requesting that the Commission approve a surge deferral for 2025 which is the seventh and last year of the program? Yes. The program remains on track to be completed in the seven years originally
13 14 15 16	<b>Q27.</b> A27.	Is the Company requesting that the Commission approve a surge deferral for 2025 which is the seventh and last year of the program? Yes. The program remains on track to be completed in the seven years originally contemplated but the Commission has previously approved the surge deferrals in
13 14 15 16 17	<b>Q27.</b> A27.	Is the Company requesting that the Commission approve a surge deferral for 2025 which is the seventh and last year of the program? Yes. The program remains on track to be completed in the seven years originally contemplated but the Commission has previously approved the surge deferrals in two-year increments. The Commission approved tree trim surge funding through
13 14 15 16 17 18	<b>Q27.</b> A27.	Is the Company requesting that the Commission approve a surge deferral for 2025 which is the seventh and last year of the program? Yes. The program remains on track to be completed in the seven years originally contemplated but the Commission has previously approved the surge deferrals in two-year increments. The Commission approved tree trim surge funding through 2024 in the Company's last general rate case, as stated above. To complete the tree
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> </ol>	<b>Q27.</b> A27.	Is the Company requesting that the Commission approve a surge deferral for 2025 which is the seventh and last year of the program? Yes. The program remains on track to be completed in the seven years originally contemplated but the Commission has previously approved the surge deferrals in two-year increments. The Commission approved tree trim surge funding through 2024 in the Company's last general rate case, as stated above. To complete the tree trim surge program, the Company is requesting that the Commission approve a
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> </ol>	<b>Q27.</b> A27.	Is the Company requesting that the Commission approve a surge deferral for 2025 which is the seventh and last year of the program? Yes. The program remains on track to be completed in the seven years originally contemplated but the Commission has previously approved the surge deferrals in two-year increments. The Commission approved tree trim surge funding through 2024 in the Company's last general rate case, as stated above. To complete the tree trim surge program, the Company is requesting that the Commission approve a surge funding deferral of \$43.7 million for calendar year 2025 which is the seventh
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> </ol>	<b>Q27.</b> A27.	Is the Company requesting that the Commission approve a surge deferral for 2025 which is the seventh and last year of the program? Yes. The program remains on track to be completed in the seven years originally contemplated but the Commission has previously approved the surge deferrals in two-year increments. The Commission approved tree trim surge funding through 2024 in the Company's last general rate case, as stated above. To complete the tree trim surge program, the Company is requesting that the Commission approve a surge funding deferral of \$43.7 million for calendar year 2025 which is the seventh and last year of the surge program.
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> </ol>	<b>Q27.</b> A27.	Is the Company requesting that the Commission approve a surge deferral for 2025 which is the seventh and last year of the program? Yes. The program remains on track to be completed in the seven years originally contemplated but the Commission has previously approved the surge deferrals in two-year increments. The Commission approved tree trim surge funding through 2024 in the Company's last general rate case, as stated above. To complete the tree trim surge program, the Company is requesting that the Commission approve a surge funding deferral of \$43.7 million for calendar year 2025 which is the seventh and last year of the surge program.
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>23</li> </ol>	Q27. A27. Q28.	Is the Company requesting that the Commission approve a surge deferral for 2025 which is the seventh and last year of the program? Yes. The program remains on track to be completed in the seven years originally contemplated but the Commission has previously approved the surge deferrals in two-year increments. The Commission approved tree trim surge funding through 2024 in the Company's last general rate case, as stated above. To complete the tree trim surge program, the Company is requesting that the Commission approve a surge funding deferral of \$43.7 million for calendar year 2025 which is the seventh and last year of the surge program.

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1	A28.	In the Case U-20162 May 2, 2019 Order, the Commission specified that the return
2		earned on the tree trim surge regulatory asset deferrals would accrue at the short-
3		term debt rate. Lastly, the Commission stated that the Company may seek recovery
4		of the regulatory asset in a future rate case or through securitization.
5		
6	Q29.	In previous rate cases the Company discussed its plans to seek securitization
7		of the regulatory asset. Has the Company sought the securitization of any of
8		the deferred tree trimming assets yet?
9	A29.	Yes. In Case No. U-21015, the Company requested securitization of \$116.2 million
10		of its tree trim deferred asset balance through June 30, 2021. The requested amount
11		represented the total qualified assets of \$156.9 million (\$43.3 million in 2019, \$74.1
12		million in 2020, and \$38.3 million through June 30, 2021, plus interest of \$1.2
13		million) net of deferred federal income tax charges (DFIT) of \$40.6 million. The
14		Commission approved the securitization of and recovery up to the total qualified
15		costs for the tree trim deferred asset of \$156.9 million inclusive of DFIT and the
16		Company has securitized that expense.
17		
18	Q30.	How has the Company treated the tree trim surge regulatory asset in this
19		general rate case filing?
20	A30.	The Company, as previously ordered by the Commission, has included a "return
21		on" the tree trim surge regulatory asset at only the short-term cost of debt included
22		in this case. However, Witness Lepczyk discusses why the Company believes the
23		return on should be comprised of both permanent debt and equity. The
24		Commission's Order in the U-21015 securitization filing required the proceeds
25		from the securitization be used to retire both permanent debt and equity for the tree

1 trim surge regulatory asset. Consistent with that determination, the Company 2 should be allowed to recover its actual financing cost in a commensurate manner. 3 The revenue requirement for the deferred amount is calculated by Company 4 Witness Vangilder on Exhibit A-11, Schedule A1.1 using short term debt costs 5 supported in this case by Witness Lepczyk. 6 7 Q31. When does the Company anticipate making its next securitization filing for 8 the tree trim surge regulatory asset? 9 A31. The Company anticipates reaching a balance of approximately \$150 million in the 10 tree trim regulatory asset again in late 2023. However, since the upfront costs 11 associated with securitization bonds are sizable and largely fixed, the Company 12 intends on waiting until a larger deferred balance accumulates (i.e., greater than 13 \$200 million), as this will more efficiently spread the fixed costs and reduce overall 14 securitization costs to customers. Although a securitization filing capturing costs 15 through 2023 is technically feasible in 2024, the Company also needs to consider 16 the size of the anticipated surge amounts through the remainder of the surge 17 scheduled to end in 2025. Since the remaining 2024 and 2025 expenditures are not 18 anticipated to attain the required scale needed for a standalone filing, DTE Electric 19 is planning to file a final tree trim related securitization after the surge program 20 concludes in 2025, capturing all expenditures not previously securitized.

21

#### 22 Corporate Memberships

23 Q32. How does the Company determine which corporate memberships to acquire?

A32. The Company acquires and maintains corporate memberships that help in its
 mission to provide safe, affordable, clean and reliable energy. Decisions regarding

which memberships to obtain are typically made by individual business units. A list of the corporate memberships included in DTE Electric's O&M expense are shown on Exhibit A-27, Schedule Q1. As shown in this exhibit, each membership generally falls under the auspices of one business unit. Q33. Has the Commission provided guidance on how the Company should support its Corporate Memberships in this and future rate cases? Yes. In its November 18, 2022 order in Case No. U-20836 on page 306, the Commission directs the Company as follows: "The Commission directs DTE Electric to file in its future rate cases an exhibit containing an itemized list of projected costs associated with membership fees and justification for why these costs are in customers' interest." Q34. Has the Company itemized the projected costs associated with membership fees and included justifications why these costs are in customers' best interest?

17 A34.	Yes. Exhibit A-27, Schedule Q1 includes the costs and a description for each
18	membership included in the Company's projected test year. The exhibit is seven
19	pages with pages 1 - 2 displaying, in alphabetical order, the corporate memberships
20	which are nondiscretionary. Pages $3 - 7$ display, in alphabetical order, those
21	memberships which are discretionary. The descriptions include the benefit these
22	memberships offer. Additionally, corporate memberships which are discretionary
23	and exceed \$100,000 are further supported by other witnesses in the case
24	representing the primary business unit that utilizes the membership. Exhibit A-27,

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A33.

		A. CROZIER
Line <u>No.</u>		U-21297
1		Schedule Q1 provides the witness names along with their associated business unit
2		for those memberships.
3		
4	Q35.	Do any of the membership costs included in the Company's revenue
5		requirement in this case involve lobbying activities?
6	A35.	No. Any memberships, or portions of memberships, related to lobbying activities
7		are excluded from DTE Electric's revenue requirement. Witness Uzenski supports
8		how certain memberships and certain membership costs have been excluded. As
9		mentioned above the costs shown on Exhibit A-27 Schedule Q1 represent the costs
10		that are proposed for inclusion in rates, exclusive of lobbying fees. The amounts
11		have not been adjusted for inflation on Exhibit A-27 Schedule Q1 but are included
12		in the Company's revenue requirement with an inflation adjustment.
13		
14	Q36.	What benefits does the Company receive from DTE Electric's memberships in
15		the organizations listed on Exhibit A-27, Schedule Q1?
16	A36.	In addition to the benefits included in each membership's description, the benefits
17		the Company and its customers receive from the memberships listed in Exhibit A-
18		27, Schedule Q1 pages 2 through 7 generally fit into one or more of the following
19		broad categories:
20		• Benchmarking - helps the Company understand how its performance and
21		practices compare to its peers,
22		• Best practices - provides insights into industry best practices and potential
23		opportunities for implementation based on those insights,

<u>No.</u>		
1		• Research – provides access to research that the Company would otherwise
2		have to perform on its own, and leads to access to information at a lower
3		cost than if each member organization performed the research on their own,
4		• Networking – helps build relationships with peers that improves the flow of
5		communication between people and companies leading to a greater
6		awareness of industry trends, emerging technologies, emerging issues, and
7		resources.
8		
9	Q37.	Are you providing additional support for any of the corporate memberships
10		requested for recovery?
11	A37.	Yes. In addition to our operating groups (e.g., Distribution, Generation), the
12		Company leverages Edison Electric Institute (EEI) to the benefit of its customers
13		through many internal organizations. EEI members are afforded the opportunity to
14		establish connections with other companies through the EEI network. Some
15		ongoing and recent examples of how the Company's EEI participation benefits
16		customers include:
17		• Mutual assistance coordination across the nation which enables DTE
18		Electric to quickly secure resources for storm restoration. The industry has
19		no other mutual assistance structure;
20		• Information on technology industry security initiatives and best practices;
21		• Assistance identifying and networking with diverse suppliers specific to the
22		utility industry as well as sharing best practices regarding supplier diversity;
23		• Benchmarking on utility-driven economic development;
24		• Knowledge building regarding FERC Order 2222 and its implications for
25		utility system preparation and operation;

Line

		A. CROZIER
Line <u>No.</u>		U-21297
1		• Best practice sharing from transportation electrification programs around
2		the nation; and
3		• Learning from industry experts and leaders on important topical subjects
4		such as battery operations and risk mitigation, decarbonization, and non-
5		wire alternatives.
6		
7	Ford 2	MIGreenPower (MIGP) Contract
8	Q38.	What has the Commission said regarding the recently approved Ford MIGP
9		contract?
10	A38.	In its order dated December 21, 2022 in Case No. U-21285 (December 21 Order),
11		the Commission approved the Company's MIGP contract with Ford and requested
12		explanation in subsequent general rate cases regarding how the contract complies
13		with the Commission's previous directives regarding special contracts and
14		Michigan Administrative Code, R 460.2031.
15		
16	Q39.	Did the Commission offer any further information in the December 21 Order?
17	A39.	Yes. The December 21 Order includes a reference to a Commission order in Case
18		No. U-10646 dated March 23, 1995 (March 23 Order). The reference as contained
19		in the December 21 order at page 4 is as follows:
20		"Based on Mich Admin Code, R 460.2031 (Rule 31) <sup>1</sup> and the March 23,
21		1995 order in Case No. U-10646 (March 23 order) <sup>2</sup> , the Staff recommends
22		that the Commission direct the company to file any amendments to the
23		company's contract in this docket."
24		Footnote 2 states:

<u>No.</u>		
1		"Speaking to cost allocation, the Commission found in the March 23 order
2		that, "unless [The] Detroit Edison [Company] can make a compelling
3		showing why a different ratemaking treatment is justified, the Commission
4		will not permit Detroit Edison to reallocate the costs of serving contract
5		customers to other ratepayer classes." March 23 order, p. 21."
6		
7	Q40.	What does the referenced Michigan Administrative Code R 460.2031 provide
8		with respect to special contracts?
9	A40.	The rule states:
10		Rule 31. (1) When a utility enters into a special contract to provide service
11		in a manner or at a rate not specifically covered by its filed rate schedules
12		or rules and regulations, the utility shall file an application for approval of
13		the special contract with the commission. (2) If the commission specifies
14		any modifications to the proposed special contract with its approval order,
15		then within 30 days, the utility shall file a copy of the executed special
16		contract, modified as required by the commission's order.
17		
18	Q41.	Can you briefly describe the special contracts that were the subject of Case
19		No. U-10646?
20	A41.	The special contracts that were the subject of Case No. U-10646 were special
21		manufacturing contracts (1995 special manufacturing contracts) offered by the
22		Detroit Edison Company (Detroit Edison currently DTE Electric) to General
23		Motors, Ford Motor Company, and Chrysler (currently Stellantis). These special
24		manufacturing contracts included discounts to approved tariff rates in exchange for
25		a commitment from these customers that they would continue as customers of

Line

Line <u>No.</u>		A. CROZIER U-21297
1		Detroit Edison. The Commission approved the contracts but required a showing in
2		subsequent rate cases that these discounts to the Company's approved D6 tariff rate
3		were in the best interest of all other customers.
4		
5	Q42.	Can you describe the context for the Ford contract approved on December 21,
6		2022 in Case No. U-21285?
7	A42.	Yes. In June 2021, the Company received an order approving the settlement of its
8		consolidated REP and Voluntary Green Pricing (VGP) cases (Case Nos. U-20713
9		and U-20851). This settlement included a section allowing customers to request
10		renewable energy projects specific to their needs. Specifically, Section 9 states that
11		the Company will include a Customer-Requested offering in its MIGP program that
12		will be implemented through the execution of individual special contracts that are
13		filed with the Commission on an ex parte basis. The Ford contract was the first
14		contract approved pursuant to this agreement.
15		
16	Q43.	What are the basic terms of the Ford MIGP contract?
17	A43.	DTE Electric contracted with Ford for up to a 35-year period to add up to 675 MWs
18		of solar projects in Michigan to help Ford reach its goal of 100% clean energy. The
19		contract includes early termination language designed to hold other customers
20		harmless if an unforeseen event prevents Ford from carrying out the full contract
21		term. The contract has been designed to mirror the subscription charge and
22		associated bill credit methodology of the current MIGP Rider 17 for customers,
23		with greater than 2,500 MWhs of annual enrollments which took effect on August
24		20, 2022. The projects supporting the Ford MIGP contract are estimated to be in
25		commercial operation beginning approximately in 2025. The Ford MIGP contract,

Line <u>No.</u>		A. CROZIER U-21297
1		unlike the 1995 special manufacturing contracts, does not provide a discount to the
2		Company's Commission approved Rider 17 tariff, which is available to all DTE
3		Electric customers.
4		
5	Q44.	What are the major differences between the approved Rider 17 tariff and the
6		Ford contract?
7	A44.	There are several related differences:
8		• Contract requirement and term
9		One difference is that the Ford contract is a 35-year contract, while other
10		Rider 17 customers with initial annual enrollments of 2,500 MWh or more
11		are obligated to sign a contract but can elect terms as short as five years.
12		Further, customers with annual enrollments of less than 2,500 MWh are not
13		required to sign a written contract.
14		• Contract termination
15		Another key difference is that it is not until year 25 that Ford has an option
16		to terminate the contract without a termination fee. Other Rider 17
17		customers with annual enrollments of 2,500 MWhs or more can terminate
18		at any time with one year's notice. Rider 17 customers with less than 2,500
19		MWhs may discontinue their enrollment in Rider 17 at any time.
20		• Contract termination fees
21		Lastly, the cost of termination for Ford under their MIGP contract requires
22		them to pay an early termination fee prior to year 25 of the contract. This
23		termination fee is substantial and the contract, in its entirety, was reviewed
24		with Staff prior to filing in Case No. U-21285. The actual fee schedule was
25		redacted prior to filing with the Commission. Other Rider 17 customers with

Line		A. CROZIER U-21297
<u>No.</u>		
1		more than 2,500 MWhs of annual enrollments are only obligated for up to
2		one year of subscription fees should they terminate their contracts early.
3		Customers with less than 2,500 MWhs of annual enrollment have no
4		termination fee.
5		
6	Q45.	Are other customers disadvantaged or harmed by these differences?
7	A45.	No, customers are not harmed or disadvantaged but rather benefit relative to the
8		standard terms for other customers electing the Commission-approved Rider 17
9		tariff. Ford's obligation to a longer contract term, restricted termination period, and
10		termination fees designed to mitigate any impact to other customers provides DTE
11		Electric with an enhanced certainty of revenue recovery for the costs of the
12		underlying assets compared to other Rider 17 customers.
13		
14	Q46.	Is there any other fundamental difference between the Ford MIGP contract
15		and the 1995 special contracts?
16	A46.	Yes. The other fundamental difference is that the Ford MIGP contract and design
17		are born from renewable legislation and years of supporting regulation
18		incentivizing electric utilities to provide customer-responsive renewable
19		generation. MIGP is DTE Electric's Commission-approved voluntary green pricing
20		program (VGP). VGPs are required by Public Act 342 Sec. 61.
21		
22	Q47.	Does the Ford contract impact cost allocation or base rates in the instant case?
23	A47.	No. The contract revenues from Ford are projected to begin in approximately 2025
24		or beyond once the projects supporting the contract become operational.
25		

1	Q48.	Will the Ford MIGP contract impact the cost allocation or base rates in
2		general rate cases in the next five years?
3	A48.	No. The revenues and costs associated with this contract, as with the Rider 17
4		revenue and costs, are all reconciled in the Company's REP filings.
5		
6	Q49.	Is the Ford MIGP contract being subsidized by other customers?
7	A49.	No. Ford will pay a levelized subscription fee based on the final costs of the solar
8		projects supporting its 35-year contract. In any one year of the contract, the
9		levelized rate may be more or less than that year's revenue requirement. However,
10		the subscription fee is designed to recover the revenue requirements of the projects
11		over the life of the contract. The levelized cost of energy protocol used to calculate
12		the subscription fee is the same methodology used to calculate other MIGP
13		customers' subscription fees pursuant to Rider 17 and is the same levelized cost of
14		energy protocol created and used for renewable energy plans for well over a decade.
15		Default and early termination payments have been set forth in the Ford MIGP
16		contract and agreed upon to mitigate rate impacts in the event of a customer-
17		initiated termination event.
18		
19	Q50.	Is there any way to definitively calculate, at this time, what the various
20		revenue, costs, and crediting components of the contract will be?
21	A50.	No, there is not. For instance, the subscription fee will be based on the final
22		levelized cost of energy calculation once the projects supporting the contract have
23		been completed. Similarly, the final costs will also not be definitively known until
24		project completion. Lastly, the credits provided to Ford will be based on the market

prices for energy and capacity at the time the projects are operational. The Ford 25

project completion. Lastly, the credits provided to Ford will be based on the market

Line <u>No.</u>		A. CROZIER U-21297
1		MIGP contract explicitly refers to Rider 17 for calculation of the credits for energy
2		and capacity market prices.
3		
4	Q51.	Do you believe that the Ford MIGP contract should be treated similar to the
5		special contracts approved in 1995?
6	A51.	I do not. Though both are arguably "special contracts", they are different in several
7		fundamental ways. Unlike the 1995 special contracts, the Ford MIGP contract 1)
8		does not offer a discount to any established tariff; 2) uses the same methodology as
9		an established tariff (Rider 17) to calculate revenue required from the customer
10		(subscription, fee); and 3) the revenues and costs associated with the contract do
11		not currently flow through base rates or the base rates projected in this case.
12		
13	Q52.	What requests do you have for the Commission regarding its directive on the
14		Ford MIGP Contract?
15	A52.	Given the consistency of the Ford Contract with the Company's approved Rider 17
16		tariff, I request the Commission issue an order determining that neither Michigan
17		Administrative Code, R 460.2031 nor the Commission's prior special contract
18		concerns and directives apply to the Ford MIGP contract. However, should the
19		Commission still require some showing, I request that the Commission consider the
20		Company's REP reconciliation the more appropriate venue once the contract's
21 22		commencement date has been reached.
23	<u>Introc</u>	luction of Other Witnesses
24	Q53.	How will the Company present evidence in support of its requested relief in
25		this case?

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1	A53.	The <b>C</b>	Company will present its case through 34 witnesses, including myself, as
2		descri	ibed below (in alphabetical order).
3		1)	Ms. Maheen Asghar, Principal Financial Analyst – Load Research and
4			Pricing, supports and justifies the December 1, 2023 to November 30, 2024
5			forecast allocation schedules.
6			
7		2)	Mr. Robert A. Bellini, Manager – Community Lighting, supports the energy
8			forecast for outdoor lighting; the development of the proposed rate design
9			for the outdoor lighting rate schedules (municipal lighting and other) as well
10			as supports the reasonableness of the historic and projected Community
11			Lighting O&M and the Community Lighting capital expenditures. He also
12			discusses the preventative maintenance programs and outage restoration
13			activities for community lighting.
14			
15		3)	Mr. Shawn D. Burgdorf, Manager of the Power Supply Strategy &
16			Modeling - Generation Optimization, establishes the projected wholesale
17			market energy sales revenue net of fuel including the reconciliation of 2021.
18			
19		4)	Mr. Michael S. Cooper, Director - Compensation, Benefits & Wellness,
20			presents an overview of benefit expense for DTE Electric for the 2021
21			historical test period and the December 1, 2023 through November 30, 2024
22			projected test period. He supports the Company's pension costs, other post-
23			employment benefits (OPEB) costs, active employee health care and other
24			employee benefits costs; supports labor cost escalation assumptions
25			assumed in the projected period; provides an overview of the Company's

Line <u>No.</u>	U-21297
1	compensation philosophy for non-represented employees and the role that
2	the Company's incentive plans play in the overall reasonableness of its total
3	compensation; provides an analysis of the reasonableness of the current
4	total compensation levels; describes the components of the Company's
5	short and long-term incentive plans and supports the inclusion of such costs
6	in the Company's revenue requirement, exclusive of the costs related to

total compensation levels; describes the components of the Company's short and long-term incentive plans and supports the inclusion of such costs in the Company's revenue requirement, exclusive of the costs related to DTE Energy's top five executives. In addition, Witness Cooper demonstrates that the quantifiable customer benefits of the Company's incentive plans exceed the expense, as required by the Commission's traditionally mandated cost/benefit analysis of incentive compensation expense.

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- 13 5) Mr. Jeffery C. Davis, Expert – Nuclear Strategic Business Operations, 14 supports the Company's actual nuclear O&M and capital expenditures for the 12-month historical test period ended December 31, 2021. He also 15 16 discusses and supports the reasonableness of the projected nuclear O&M and capital expenditures for the interim forecast period and the 12-month 17 18 projected test period ending November 30, 2024. In addition, he supports 19 the reasonableness of the projected Nuclear Surcharge for the projected test 20 period ending November 30, 2024.
- 21

6) Mr. Satvir Deol, Director – Substation Operations, supports, as reasonable and prudent, the historical capital expenditures for 2021 and projected capital expenditures for 2022 thru November 30, 2024, in the distribution strategic investment category of Infrastructure Redesign and Modernization

Line No. 1 and discusses the metrics and programs associated with the Company's 2 proposed IRM proposed by Company Witness Foley. 3 4 7) Ms. Morgan Elliott Andahazy, Director – Project Management 5 Organization, supports, as reasonable and prudent, the historical capital 6 expenditures for 2021 and projected capital expenditures for 2022 to 7 November 30, 2024, in the distribution strategic category of Infrastructure 8 Resilience and Hardening, and the investments in the System Operations 9 Center Modernization projects which include the construction of the new 10 Electric System Operations Center and the Alternate Systems Operations 11 Center, for the same period. In addition, her testimony will include support 12 for specific programs included in the IRM proposed by Company Witness 13 Foley. 14 15 8) Mr. Keegan Farrell, Manager - Demand Response (DR), discusses the

16 development of DR efforts that DTE Electric is conducting and provides 17 support for the expenditures and activities associated with the continuation 18 of existing programs and pilots, as well as the Company's proposals for new 19 pilots.

20

21 9) Mr. Neal T. Foley, Director - Regulatory Affairs, describes the key 22 components of the Company's proposal in this case for the establishment of 23 an IRM focused on strategic capital programs related to customer safety and 24 reliability.

25

<u>No.</u>		
1	10)	Ms. Shannen M. Hartwick, Director - Tree Trim, discusses the Company's
2		tree trimming program including the 2021 historic period expense as well
3		as the expenses for 2022 and the projected test year. She also supports
4		funding for the tree trim surge program that will enable the Company to
5		deliver the reliability goals established in its Five-Year Plan.
6		
7	11)	Mr. Michael J. Hatsios, Director - Customer Service Operations supports
8		the reasonableness and prudency of a subset of the capital projects in the
9		Company's Customer IT Portfolio. Specifically, he discusses the details
10		and benefits to customers of those projects that align with DTE Electric's
11		priorities to save customers money, enhance the customer experience,
12		promote and provide energy efficiency (EE) and renewable energy
13		opportunities for customers.
14		
15	12)	Mr. Brian L. Hill, Director - Distribution Operations Scheduling and
16		Construction supports, as reasonable and prudent, the historical capital
17		expenditures and proposed capital expenditures related to base capital
18		programs (emergent replacements, customer connections, relocations, and
19		others). In addition, he supports select strategic capital expenditures related
20		to the technology and automation projects and discusses the 4.8kV Circuit
21		Automation metrics associated with the Company's proposed IRM.
22		
23	13)	Ms. Tamara D. Johnson, Director - Revenue Management & Protection,
24		supports the details of the Company's Low-Income programs and provides
25		explanation and support for the uncollectible expense. She proposes

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Line <u>No.</u>		A. CROZIER U-21297
1		changes to the Rate Schedule D1.6 tariff provision. She also discusses
2		details of our Low-Income Assistance credits and their impact with the
3		Low-Income Self Sufficiency Program as well as the Payment Stability Plan
4		pilot.
5		
6	14)	Mr. Allen J. Kryscynski, Manager – Distribution Operations Regulatory
7		Strategy and Grid Modernization supports, the Distribution Operations'
8		Global Prioritization Model, Infrastructure Investment and Jobs Act
9		funding grants, and updates on the distribution approach to Environmental
10		Justice.
11		
12	15)	Mr. Robert J. Lee, Manager - Environmental Strategy, describes the status
13		of two significant Environmental Protection Agency regulations: the Steam
14		Electric Effluent Limitation Guidelines Rule and the Coal Combustion
15		Residuals Rule which impact the Company's coal-fired power plants.
16		
17	16)	Mr. Timothy J. Lepczyk, Assistant Treasurer and Director - Corporate
18		Finance, Insurance and Development supports DTE Electric's projected
19		capital structure and the cost of its long and short-term debt to be used in
20		the determination of DTE Electric's overall rate of return in this proceeding.
21		
22	17)	Mr. Markus B. Leuker, Manager – Corporate Energy Forecasting, provides
23		the Company's current electric sales, maximum demand, and system output
24		forecast for the period 2022-2027, including the projected 12-month test
25		period December 2023 through November 2024. He discusses the outlook

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	for the national and local economy which is the basis of the forecast.
	Witness Leuker also describes how the forecast of electric sales, maximum
	demand and system output is developed and supports the reasonableness of
	the electric sales forecast used by DTE Electric in this proceeding.
18)	Mr. Habeeb J. Maroun, Regulatory Strategy Consultant - Revenue
	Requirements Department, presents Unbundled Cost of Service (UCOS)
	Studies for DTE Electric's projected test year ending November 30, 2024.
	He also supports revenue requirement calculations for: (1) customer-related
	costs, (2) capacity charge by customer class, and (3) IRM by voltage class.
19)	Mr. Bryant F. Miller, Manager – Distribution Operation Support, discusses
	the overall DO capital investments including an overview of the DO capital
	exhibits and the forecasting methods utilized in those exhibits. He also
	discusses the variances between the 2021 actuals and the forecasted
	amounts in Case No. U-20836 as well as the 2022 and 2023 projected
	capital expenditures forecasted in Case No. U-20836 compared to the
	projections in this instant case.
20)	Mr. David C. Milo, Fuel Resource Specialist – Fuel Supply, supports DTE
	Electric Fuel Supply's and Midwest Energy Resources Company's
	operations and maintenance expense and capital expenditures for the twelve
	months ended December 2021 historical actual, and as projected for 2022
	through November 30, 2024.
	18) 19) 20)

<u>No.</u>		
1	21)	Mr. Justin L. Morren, Plant Director - Energy Supply, supports the
2		reasonableness and prudency of the O&M and capital expenditures for
3		Energy Supply steam power generation, hydraulic power generation
4		(Ludington), and other power generation for the historical test year ended
5		December 31, 2021, the 23-month bridge period ending November 30,
6		2023, and the 12-month projected test period ending November 30, 2024.
7		He provides a review of the Fossil Generation base coal unit availability
8		performance for five years prior and five years following the projected test
9		year in this instant case. He also discusses how the Environmental
10		Protection Agency's Steam Electric Effluent Limitation Guidelines Rule
11		affects required coal-fired generation investment and supports the historical
12		2021 level of capital expenditures on a plant level basis and the forecast of
13		capital expenditures planned for 2022 through November 30, 2024.
14		
15	22)	Mr. Thac K. Nguyen, Manager - Energy Waste Reduction, discusses the
16		development, future plans, and related expenditures associated with the
17		DTE Insight Program.
18		
19	23)	Ms. Kelsey Peterson, Manager – Strategic Marketing, Planning &
20		Development supports the expenditure status for existing Charging Forward
21		pilots, discusses the Charging Forward Expansion next steps, including
22		transitioning from pilots to permanent programs and associated costs, and
23		introduces the Delivered Fuel Electrification Pilot and associated costs. She
24		also supports Merchant Fees expense and certain expenditures related to the

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<u>No.</u>		0-21297
1		Advanced Customer Pricing Pilot and 2023 full time-of-day roll out; and
2		the Electric Regulated Marketing O&M expense.
3		
4	24)	Mr. Matthew Pollack, Senior Strategist - Regulatory Affairs supports the
5		commercial and industrial rate design.
6		
7	25)	Mr. Joseph E. Robinson, Director - Central Engineering for Electric
8		Distribution Operations, supports the historical O&M expenses related to
9		electric distribution activities for the 2021 historical period and for the
10		projected test period 12-months ending November 30, 2024. His testimony
11		describes the (1) Distribution Operations Overview and System
12		Performance, (2) Distribution Grid Plan (DGP) Overview and, (3)
13		Distribution O&M Overview. In addition, Witness Robinson provides a
14		description of the other Distribution Operations witnesses in this case.
15		
16	26)	Mr. Pankaj Sharma, Director – Information Officer within the Information
17		Technology Services organization, discusses the IT Capital investment
18		framework and planning process that drives prioritization of both single and
19		multi-year projects and programs; supports the Company's IT capital
20		expenditures beginning with the historic test year and extending through the
21		projected test year; and describes the variances in the actual 2021 capital
22		spend compared to the spend approved in the Company's previous general
23		rate case.
24		

Line <u>No.</u>		U-21297
1	27)	Mr. Phillip L. Smith, Director – Operational Technology for Distribution
2		Operations, supports capital related to the Advanced Metering
3		Infrastructure project, Network Management System, and the Advanced
4		Distribution Management System for the 2021 historical test period, as well
5		as the projected capital expenditures for 2022 through November 30, 2024.
6		
7	28)	Mr. Jason E. Sparks, Director – Customer Service Operations, explains the
8		Company's actual Customer Service O&M expenses for the 12-month
9		period ended December 31, 2021 and provides support for projected O&M
10		expenses for the projected test period ending November 30, 2024.
11		
12	29)	Ms. Theresa Uzenski, Manager - Regulatory Accounting, supports DTE
13		Electric's financial statements for the historical test year ended December
14		31, 2021, the interim forecast period and a twelve-month projected test
15		period ending November 30, 2024, with certain adjustments necessary for
16		presenting the financial information in the appropriate format for
17		ratemaking purposes. She supports the development of the projected test
18		year adjusted electric operating income based on forecasted changes from
19		the normalized historical electric operating income. Ms. Uzenski also
20		supports the Corporate Staff Group expenses for the historical and
21		forecasted periods and explains the function of this group and the method
22		for allocating costs to DTE Electric and the other DTE Energy subsidiaries.
23		She supports that costs recovered from other mechanisms are excluded from
24		the financial statements in this case (including the Renewable Energy
25		Program, and Energy Waste Reduction). She also supports the Corporate

Line
No.

1		Staff Group capital and O&M expenses for the historical and forecasted
2		periods and explains the function of this group including the method for
3		allocating costs to DTE Electric and other DTE Energy subsidiaries through
4		the Shared Asset charge. She also requests regulatory asset treatment for
5		certain costs associated with the Company's Delivered Fuel Electrification
6		Pilot and requests Power Supply Cost Recovery accounting treatment for
7		potential tax credits related to nuclear generation.
8		
9	30)	Mr. Kirk M. Vangilder, Principal Financial Analyst - Revenue
10		Requirements, supports DTE Electric's twelve months ended December 31,
11		2021 historical revenue deficiency. In addition, he is sponsoring Net
12		Operating Income (NOI) adjustments for interest synchronization and
13		income tax savings, as well as the revenue conversion factor. Mr. Vangilder
14		is sponsoring DTE Electric's twelve months ending November 30, 2024
15		projected revenue deficiency. He also calculates the incremental revenue
16		requirement for DTE Electric's Tree Trim Surge regulatory asset and the
17		incremental revenue requirements for DTE Electric's IRM as well as the
18		Company's proposed reconciliation process should a different amount of
19		IRM capital be placed in service than what has been approved.
20		
21	31)	Dr. Bente Villadsen, Principal at The Brattle Group, supports the cost of
22		capital for the Company. Specifically, Dr. Villadsen estimates the cost of
23		equity that DTE Electric should be allowed an opportunity to earn on the
24		equity-financed portion of its regulated utility rate base. Dr. Villadsen's
25		recommendation also considers the business and financial risk of the

			A. CROZIER
Line <u>No.</u>			U-21297
1			Company relative to the proxy companies to arrive at her recommendation
2			for the allowed Return on Equity for DTE Electric of 10.25%.
3			
4		32)	Mr. Aaron Willis, Manager - Regulatory Economics, discusses and
5			supports the Power Supply Costs and Nuclear Surcharge for the projected
6			test year, the proposed Rate Design including residential, Rider No. 14, and
7			Rate Schedule D13, IRM Surcharge Design, and Other Tariff Changes.
8			
9		33)	Ms. Sherri Wisniewski, Director - Tax Operations, supports the DTE
10			Electric Federal Income Tax, Michigan Corporate Income Tax, Municipal
11			Income Tax, property tax and other general taxes for the 2021 calendar year
12			historical period as well as the twelve months projected test period ending
13			November 30, 2024.
14			
15	Q54.	Does t	this complete your direct testimony?

16 A54. Yes, it does.

## **STATE OF MICHIGAN**

## **BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

In the matter of the Application of	)
DTE ELECTRIC COMPANY	)
for authority to increase its rates, amend	)
its rate schedules and rules governing the	)
distribution and supply of electric energy, and	)
for miscellaneous accounting authority.	)

Case No. U-21297

QUALIFICATIONS

AND

## DIRECT TESTIMONY

OF

## MAHEEN ASGHAR

## DTE ELECTRIC COMPANY QUALIFICATIONS AND DIRECT TESTIMONY OF MAHEEN ASGHAR

Line <u>No.</u>

<u>NO.</u>		
1	Q1.	What is your name, business address and by whom are you employed?
2	A1.	My name Maheen Asghar (she/her/hers). My business address is One Energy Plaza,
3		Detroit, Michigan 48226. I am employed by DTE Energy Services, LLC (DTE
4		Energy) as a Principal Financial Analyst – Regulatory Economics.
5		
6	Q2.	On whose behalf are you testifying?
7	A2.	I am testifying on behalf of DTE Electric Company (DTE Electric or Company).
8		
9	Q3.	What is your educational background?
10	A3.	I received a Bachelor of Science in Computer Science from Wayne State University
11		and a Master of Science in Information (data science and analytics) from the
12		University of Michigan.
13		
14	Q4.	Have you received any additional training?
15	A4.	I attended the AEIC Load Research & Analytics Fundamentals of Customer Load
16		Data Analysis Seminar in 2021.
17		
18	Q5.	What is your work experience?
19	A5.	I began my career at DTE Energy, in 2014, as a co-op programming student in
20		Distribution Operations (DO). I transitioned to a full-time position as an Operations
21		Analyst within DO in 2016, where I worked primarily with outage data. In 2019, I
22		accepted a position in Corporate Strategy, a role in which I supported key
23		operational and strategic work across the Company. I joined Regulatory Affairs in
24		2021, as a Principal Financial Analyst.

		M. ASGHAR
Line <u>No.</u>		U-21297
1	Q6.	What are your current duties and responsibilities?
2	A6.	Currently, I am a Principal Financial Analyst in Regulatory Affairs. In this
3		position, I am responsible for evaluating customer class usage characteristics,
4		developing allocation schedules for use in cost-of-service studies and rate design,
5		and for measuring and evaluating demand response programs offered by the
6		Company.
7		
8	Q7.	Have you previously sponsored testimony before the Michigan Public Service
9		Commission (MPSC or Commission)?
10	A7.	Yes, I have. I have sponsored testimony in the following case:
11		U-20836 DTE Electric 2022 General Rate Case

1	<u>Purpo</u>	Purpose of Testimony		
2	Q8.	What is the <b>p</b>	ourpose of you	r testimony in this proceeding?
3	A8.	The purpose	of my testime	ony is to support and justify the December 2023 to
4		November 20	24 forecast allo	ocation schedules.
5				
6	Q9.	Are you spor	nsoring any ex	hibits in this proceeding?
7	A9.	Yes. I am su	pporting the fol	llowing exhibits:
8		<u>Exhibit</u>	<u>Schedule</u>	Description
9		A-5	E2	Cost of Service Allocation Methodology Diagram
10		A-5	E3	Allocation Schedule Description
11		A-17	G1.1	2023/2024 Forecast Energy Allocation Schedules
12		A-17	G1.2	Demand and Energy Allocation Percentages by Rate
13				Class
14				
15	Q10.	Were these e	xhibits prepai	red by you or under your direction?
16	A10.	Yes, they wer	e.	
17				
18	Q11.	What are the	e sources of da	ta used for the allocation schedules?
19	A11.	The Decembe	er 2023 to Nove	ember 2024 forecast allocation schedules are based on
20		2021 custome	er class sales	data obtained from the 2021 Total System Analysis
21		(TSA). The fo	precast allocation	on schedules are based on the energy sales forecast for
22		the residentia	l, commercial a	and industrial classes supported by Company Witness
23		Leuker, the st	reet lighting ar	nd traffic signals sales forecast supported by Company
24		Witness Bell	ini, and the fo	precast billing determinants supported by Company

Line <u>No.</u>		<b>M. ASGHAR</b> U-21297
1		Witness Willis. These sales levels are shown with losses on Exhibit A-17, Schedule
2		G1.1.
3		
4	Backg	ground and Basis for Allocation Schedules
5	Q12.	Are there any technical terms used in your testimony that may require
6		explanation?
7	A12.	Yes. To aid in understanding and to avoid confusion, I am defining the following
8		terms that I use throughout my testimony:
9		• Customer Class or Class of Service: A set of customers with similar
10		characteristics who have been grouped for the purpose of setting an
11		applicable rate for electric service.
12		• Total System Analysis (TSA): The study of all customer classes that
13		identifies the hourly demand values for all hours of the year. This is the
14		foundation of allocation schedules.
15		• Energy: The total kilowatt-hours (kWh) or megawatt-hours (MWh)
16		supplied to or used by an individual customer or customer class.
17		• Demand: The rate at which electric energy is used at a given instant or
18		averaged over a designated time interval. Typically, demand is expressed
19		in kilowatts (kW) or megawatts (MW).
20		• Service Area System Peak Demand: The highest hourly demand for all
21		customers (full service and choice) served on the DTE Electric distribution
22		system within a specific period (day, month, year, etc.). Service Area
23		System Peak Demand is commonly referred to as the 'system peak.'
24		<ul> <li>Bundled Peak Demand: The highest hourly demand for all customers served</li> </ul>
25		by DTE Electric's production system within a specific period (day, month,

<u>No.</u>		
1		year, etc.). Bundled Peak Demand is commonly referred to as 'bundled
2		peak.'
3	•	Coincident Peak Demand (CP): The demand of any customer class within a
4		specific period (day, month, year, etc.) that occurs at the same time as the
5		system peak or the bundled peak demand for the same period.
6	•	12CP: The demand value derived by averaging the actual demand values
7		registered on the monthly system or bundled peak hours for January through
8		December for each customer class.
9	•	4CP: The demand value derived by averaging the actual demand values
10		registered on the monthly bundled peak hours for June through September
11		for each customer class.
12	•	Non-Coincident Peak Demand: The maximum demand of any customer
13		class within a specific period but not necessarily occurring at the time of the
14		system peak demand for that period.
15	•	Losses: A term used to define the difference between the electrical energy
16		delivered to a customer (or a given point on the electrical distribution
17		system) and the amount of electrical energy that must be generated at the
18		power plant to serve that customer. In other words, losses refer to the
19		difference in the amount of power generated from the power plant and the
20		point of delivery.
21	•	Load Factor: The ratio, in percent, of the total energy over a designated
22		period of time to the maximum hourly demand (bundled or system)
23		occurring in that period. Load factor is calculated by the formula:
24		LF (%) = (Total Energy / (Peak Demand * No. of Hours)) * 100

Line

		M. ASGHAR
Line <u>No.</u>		U-21297
1		<ul> <li>Customer-Owned: Industrial customers that use customer owned</li> </ul>
2		substations.
3		<ul> <li>DTE-Owned: Industrial customers that use DTE Electric single customer or</li> </ul>
4		joint-use general distribution substations.
5		<ul> <li>Transmission Voltage Level: Served directly from the transmission system</li> </ul>
6		at 120 kV or above, or from the transmission system through a DTE-owned
7		substation dedicated or primarily providing service to the customer and
8		located on or immediately adjacent to the customer's premises.
9		<ul> <li>Sub-transmission Voltage Level: Served directly from the sub-transmission</li> </ul>
10		system at voltages from 24 kV to 41.6 kV or from the sub-transmission
11		system through a DTE-owned substation dedicated or primarily providing
12		service to the customer and located on or immediately adjacent to the
13		customer's premises.
14		• Primary Voltage Level: Served directly from the primary distribution
15		system at a nominal voltage between 4.8 kV and 13.2 kV who does not
16		qualify as either a transmission voltage customer or a sub-transmission
17		voltage customer.
18		<ul> <li>Secondary Service: Served directly from the secondary distribution system</li> </ul>
19		at a nominal voltage less than or equal to 4.8 kV and who does not qualify
20		as either a transmission voltage customer, sub-transmission voltage
21		customer or a primary voltage customer.
22		
23	Q13.	What is the purpose of the allocation schedules you have developed?
24	A13.	Allocation schedules are developed using customer class sales, data from Advanced
25		Metering Infrastructure (AMI), and quantitative methods to determine the extent

Line No.

> 1 (expressed as a percentage) that each customer class uses the various portions of 2 the electrical system. In this case, the customer class usage percentages determined 3 in the allocation schedules are one of the inputs used by Company Witness Maroun 4 to determine customer class cost responsibility. Because all customer classes do 5 not utilize the full distribution system to take delivery of electrical service, the 6 allocation schedules are developed to assign only the portions of the system used 7 by each customer class. Exhibit A-5, Schedule E2, is a diagram which reflects the 8 applicability of allocation schedules to customer class.

9

#### 10 Q14. How did you develop the allocation schedules?

11 A14. There are 13 forecast allocation schedules that I developed for use in cost-of-service 12 studies (see Exhibit A-5, Schedule E3 for a description of each schedule). Each 13 schedule was developed to allocate to each customer class's utilization of a 14 particular part of the electrical system, which is the industry standard practice for 15 developing allocation schedules. Schedule 100, shown in Exhibit A-17, Schedule 16 G1.2, is based on the class's forecasted energy consumption. and the remaining 10 17 allocation schedules described in Exhibit A-5, Schedule E3, are based on the 18 forecasted demand that a customer class places on the various portions of the 19 electrical system. The allocation schedule numbers and the associated portion of 20 the electrical system they represent are shown schematically on Exhibit A-5, 21 Schedule E2.

22

#### 23 Q15. Why does the measurement basis differ for each allocation schedule?

A15. The measurement basis for each allocation schedule is based on the design and
 service requirements for each portion of the electrical system. Specifically,

Line <u>No.</u>		M. ASGHAR U-21297
1		forecasted energy is used for Power Plant Energy Production (Schedule 100)
2		required to serve customers. As customers use energy, they create a demand (rate
3		at which energy is used and/or delivered) on the system.
4		
5		The output capacity of power plant production is designed considering the peak
6		demand requirements of the production system, measured as the bundled peak
7		demand. Production Schedules 200A and 200B are measured based on the
8		forecasted bundled 4CP. Schedule 201 – Distribution is based on the forecasted
9		12CP of the of the Service Area.
10		
11		Schedules 202, 203A, 203B, 203C, 204 and 205 refer to substations, high voltage
12		lines and transformers, which are designed to carry the maximum load required by
13		the customer classes they serve regardless of whether the class maximum demand
14		occurs at the same time or a different time as the system peak. The forecasted non-
15		coincident peak demand is the measurement basis for these allocation schedules.
16		
17		Low voltage secondary lines are designed to serve the absolute maximum demand
18		level of the customers they feed. Therefore, Schedule 300 is based upon the
19		forecasted sum of the individual customer maximum demands.
20		
21	<b>Forec</b>	ast Allocation Schedules
22	Q16.	How was the 2021 TSA used to develop the demand values determined for the
23		forecast allocation schedules?
24	A16.	The basis for the forecast allocation schedules developed for this instant case are
25		the forecasted net sales values presented in Witness Leuker's Exhibit A-15,

Line
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1		Schedule E1. However, because Witness Leuker's system peak demand forecast
2		does not contain the associated customer class level demand values necessary for
3		allocation schedule development, it was necessary to develop these corresponding
4		demand values by customer class. This was done by applying historical load factors
5		to the forecast energy values using industry standard load research principles to
6		derive demand values using energy and load factor. Therefore, forecast demands
7		were calculated by dividing the net forecast energy values without losses, by the
8		product of the historic load factor and annual hours.
9		
10	Q17.	How were the appropriate historic load factors determined?
11	A17.	A 5-year average load factor was derived from years 2017-2021 and used for each
12		cost-of-service class.
13		
14	Q18.	Why is using the 5-year average historical load factor a better representation
15		of the class' performance than the actual 2021 historic load factor?
16	A18.	Using the 5-year average load factor accounts for any abnormalities in any single
17		year and smooths out any variability due to weather, or other anomalies such as
18		economic conditions.
19		
20	Q19.	Why is using average historical load factors a reasonable method of
21		determining forecast demand values?
22	A19.	This approach is reasonable because it utilizes industry standard load research
23		principles that are defined in the "The Art of Rate Design", published by the Edison
24		Electric Institute (EEI), taught in the EEI Rate Fundamentals Course, and published
25		in Chapter 7 of the Association of Edison Illuminating Companies (AEIC) Load

Line No.		M. ASGHAR U-21297
1		Research Manual, 3rd Edition. These sources define the relationship of load factor
2		to demand and the principle of using energy and load factor to calculate demand.
3		
4	Q20.	How did you develop the December 2023 to November 2024 forecast allocation
5		schedules?
6	A20.	I applied the 5-year average load factors to the forecasted energy sales received
7		from Witness Leuker to produce the December 2023 to November 2024 forecast
8		schedules shown in Exhibit A-17, Schedule G1.1.
9		
10	Q21.	How are line losses used in forecast allocation schedules?
11	A21.	Line loss factors are used as a multiplier in allocation schedules to increase the
12		energy or demand value for a given schedule to reflect the amount of production
13		needed to serve the customer class. Line losses were measured by voltage level,
14		allowing allocation schedules to accurately reflect demands on the system caused
15		by different classes of customers.
16		
17	Q22.	Are the allocation schedules defined in your testimony developed using
18		established principles and methods?
19	A22.	Yes. I used the industry recognized and accepted load research principles supported
20		by EEI and AEIC. The methods I used are consistent with the methods used by the
21		Company in all its electric general rate cases filed since 2014.
22		
23	Q23.	Does this complete your direct testimony?
24	A23.	Yes, it does.

## STATE OF MICHIGAN

## BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)
DTE ELECTRIC COMPANY	)
for authority to increase its rates, amend	)
its rate schedules and rules governing the	)
distribution and supply of electric energy, and	)
for miscellaneous accounting authority.	)

Case No. U-21297

## QUALIFICATIONS

#### AND

#### DIRECT TESTIMONY

OF

### ROBERT A. BELLINI

## DTE ELECTRIC COMPANY QUALIFICATIONS AND DIRECT TESTIMONY OF ROBERT A. BELLINI

## Line <u>No.</u>

1	Q1.	What is your name, business address and by whom are you employed?
2	A1.	My name is Robert A. Bellini (he/him/his). My business address is 8001 Haggerty,
3		Belleville, Michigan 48111. I am employed by DTE Electric Company (DTE
4		Electric or Company) as Manager of Community Lighting.
5		
6	Q2.	On whose behalf are you testifying?
7	A2.	I am testifying on behalf of DTE Electric.
8		
9	Q3.	What is your educational background?
10	A3.	I graduated from Central Michigan University with a Bachelor of Science degree
11		in Business Administration in 1999. In 2005, I graduated from Oakland University,
12		with a Master of Accountancy degree.
13		
14	Q4.	What is your work experience?
15	A4.	From 2005 until 2008, I was employed by Deloitte & Touche LLP as a Financial
16		Auditor. While employed at Deloitte & Touche, I passed the Certified Public
17		Accountant (C.P.A.) examination and became a licensed C.P.A. in 2007. In 2007,
18		I was promoted to Senior Auditor on client engagements. In this role, I was
19		responsible for tailoring each audit based on a client's industry and the risks
20		inherent in their operations, supervising the audit fieldwork, and communicating
21		the audit issues and results with client management.
22		
23		In 2008, I joined DTE Energy as a Financial Auditor. My responsibilities included
24		executing both financial and Sarbanes-Oxley (SoX) audits in support of the DTE
25		Energy 10K annual filing under the guidance of our external auditor,

1		PriceWaterhouseCoopers (PWC). In 2010, I was promoted to Senior Auditor. My
2		responsibilities included planning, scoping, and executing both financial and
3		operational audits. In 2013, I was promoted to Principal Supervisor of the Joint
4		Use department. My responsibilities included developing budgets, forecasting, and
5		negotiating joint use agreements with various attaching entities. In 2016, I was
6		promoted to Manager, Joint Use. In 2018, I was promoted to Manager, Community
7		Lighting.
8		
9	Q5.	Do you hold any certifications or are you a member of any professional
10		organizations?
11	A5.	Yes. I am a registered Certified Public Accountant (CPA).
12		
13	Q6.	What are your current duties and responsibilities?
14	A6.	In this capacity, I am responsible for managing the marketing and sales, budgeting
15		and forecasting, planning and construction and asset management for
16		approximately 199,000 DTE Electric-owned streetlights and outdoor protective
17		lights. I also manage the maintenance and provision of energy to municipally
18		owned streetlights and the provision of energy-only service to municipalities, in
19		accordance with DTE Electric's MPSC-approved tariffs. DTE Electric's assets
20		related to these services include mercury vapor, metal halide, high pressure sodium,
21		and light-emitting diode (LED) luminaires.
22		
23	Q7.	Have you previously sponsored testimony before the Michigan Public Service
24		Commission (MPSC or Commission)?
~ -		

Line <u>No.</u>			<b>R. A. BELLINI</b> U-21297
1	U-20561	2019 DTE Electric General Rate Case	
2	U-20836	2022 DTE Electric General Rate Case	

## 1 **Purpose of Testimony**

2	Q8.	What is the purpose of your testimony?				
3	A8.	The purpose of my testimony is to support the following topics related to DTE				
4		Electric's lighting assets: a) cost recovery of O&M and capital expenditures, an				
5		b) rate design. Specifically, I will discuss the following issues:				
6		• Describe the portfolio of Community Lighting assets;				
7		• Support the energy forecast for the various outdoor lighting rates including				
8		automated traffic signal (ATS) rates and metered street lighting rates;				
9		• Describe the Company's preventative maintenance programs;				
10		• Discuss the Company's outage restoration activities;				
11		• Support and discuss the Company's actual Community Lighting O&M				
12		expenses for the historical period which ended December 31, 2021, and the				
13		projected Community Lighting O&M expenses for the 12-month projected				
14		test period ending November 30, 2024;				
15		• Support and discuss Community Lighting's actual capital expenditures for				
16		the historical period which ended December 31, 2021, and the projected				
17		Community Lighting capital expenditures for the 12-month projected test				
18		period ending November 30, 2024;				
19		• Support and discuss Community Lighting's light emitting diode (LED)				
20		selection methodology;				
21		• Support the proposed rate design for the outdoor lighting (municipal and				
22		other) and ATS tariff offerings using the lighting model.				
23						
24	Q9.	Are you sponsoring any exhibits in this proceeding?				
25	A9.	Yes. I am sponsoring in whole, or in part, the following exhibits:				

## Line

Line <u>No.</u>			U-21297
1	<u>Exhibit</u>	<u>Schedule</u>	Description
2	A-12	B5.5	Projected Capital Expenditures – Community
3			Lighting
4	A-13	C5.6	Projected Operation and Maintenance
5			Expenses – Distribution Expenses
6	A-16	F3	Present and Proposed Revenues by Rate
7			Schedule – 12 months ending November 30,
8			2024
9	A-16	F8	Proposed Tariff Sheets
10	A-25	01	Community Lighting Outdoor Lighting

12 A-25 O2 Community Lighting Outdoor Lighting **Outage Cost** 13

**Outage Duration** 

14 A-25 O3 HID-to-GreenCobra 400K Crossover Chart

15

11

16 I am sponsoring line 23 within Exhibit A-13, Schedule C5.6, page 1 of 2, and the pages specific to the residential and commercial outdoor protective lighting (OPL) 17 18 and municipal classes within Exhibit A-16, Schedule F3. This includes pages 46 19 through 57. On Exhibit A-16, Schedule F8, I sponsor the OPL and municipal 20 tariffs, while Company Witness Willis sponsors the tariffs for the remaining 21 customer classes.

22

23 Were these exhibits prepared by you or under your direction? Q10.

24 A10. Yes, they were.

25

#### 1 Community Lighting Assets

# Q11. Could you describe the portfolio of Community Lighting assets that DTE Electric owns, operates, and maintains on behalf of its customers?

4 A11. DTE Electric owns, operates, and maintains approximately 199,000 Community 5 Lighting assets which include municipal, commercial, and residential customers. 6 Additionally, there are approximately 82,000 streetlights which are owned by the 7 municipal customer (E1 Option III), and approximately 6,400 municipal-owned 8 Automated Traffic Signals (E2). Municipal streetlights (E1 Option I and II) include 9 roadway and residential streetlights within municipal and/or city limits. These 10 streetlights owned by DTE Electric are installed at the request of the city or 11 municipality. DTE Electric also installs Outdoor Protective Lighting (OPL) for 12 commercial (D9 Commercial) and residential (D9 Residential) customers. 13 Examples of commercial OPL solutions include parking lot lighting systems (i.e. 14 restaurants or strip malls) and residential OPL solutions such as lights installed on 15 a customer's property. Ownership of Community Lighting assets is detailed in Table 1 below: 16

17

#### Table 1: Community Lighting Assets<sup>1</sup>

Asset Type	Asset Ownership	Rate Type	# Of Assets	Description
Municipal OH &UG Street Lights	DTE Electric	E1 Option I	166,064	DTE Electric owned and maintained system
Municipal OH &UG Street Lights	Customer	E1 Option II	138	Municipal owned and DTE Electric maintained system
Municipal OH &UG Street Lights	Customer	E1 Option III	82,378	Municipal owned and maintained system
Commercial Outdoor Protective Lights	DTE Electric	D9	23,771	DTE Electric owned and maintained lighting equipment
Residential Outdoor Protective Lights	DTE Electric	D9	9,125	DTE Electric owned and maintained lighting equipment
Municipal Automated Traffic Signals	Customer	E2	6,423	Municipal owned and maintained equipment

18

Line No<u>.</u>

<sup>&</sup>lt;sup>1</sup> Light counts in the table align with the Company's rate case sales forecast

Line <u>No.</u> 1		<b>R. A. BELLINI</b> U-21297
2	Q12.	Briefly describe the various lighting technologies in service and the movement
3		toward more energy-efficient Company-owned LED lighting technology.
4	A12.	There are 4 lighting types currently in use within DTE Electric's service territory:
5		Light Emitting Diode (LED), High Pressure Sodium (HPS), Metal Halide (MH),
6		and Mercury Vapor (MV), the first three of which are still actively maintained and
7		installed upon request. LED lighting is the most energy efficient lighting type
8		available, while the remaining light types are less efficient in terms of energy
9		consumption (MV is the least efficient of the 4 light types).
10		
11		Pursuant to the Energy Policy Act of 2005, Mercury Vapor lamps became obsolete
12		due to their inefficient use of energy and inclusion of mercury as a component, and
13		effective January 2008, were banned from production in the United States. At the
14		end of 2007, MV's comprised almost 52% of DTE Electric's company owned
15		lighting assets, and the balance consisted primarily of HPS lighting (a nominal
16		number of lights were MH at the time). DTE Electric began to convert failed MV
17		lighting to LED for E1 Option I customers starting in 2017 in accordance with the
18		Commission's order on January 31, 2017, in Case No. U-18014.
19		
20		The Company has worked closely with its municipal partners, commercial and
21		residential customers over the past decade as they transition to LEDs as a preferred
22		lighting technology. Table 2 below provides a snapshot of the changes over time
23		in DTE Electric's company owned lights, from 2012 to 2022:
24		
25		Table 2: Community Lighting Assets by Lighting Type (2012-2022)

Lighting Type	2012	2017	2022
Light Emitting Diode (LED)	2,851 (1%)	53,018 (27%)	115,628 (58%)
High Pressure Sodium (HPS)	98,070 (49%)	91,422 (46%)	57,383 (29%)
Mercury Vapor (MV)	94,681 (48%)	52,518 (26%)	24,465 (12%)
Metal Halide (MH)	2,977 (2%)	2,468 (1%)	1,622 (1%)
Total Assets	198,579	199,426	199,098

## Q13. Can you provide an overview of the various lighting technologies employed within DTE's Municipal Street Lighting Business, E1 Option I?

A13. The current lighting portfolio for street lighting customers served on DTE Electric's
E1 Option I Rate Schedule referenced in Table 1 above, includes approximately
166,000 total Company owned lights as of November, 2022. Table 3 below shows
the light type breakout by total count and percentage:

- 7
- 8

9

#### Table 3: E1 Option I Light Counts by Type

Lighting TypeAsset Count% of Total AssetsLight Emitting Diode (LED)106,24364%High Pressure Sodium (HPS)43,83926%Mercury Vapor (MV)14,5759%Metal Halide (MH)1,4071%

10

While the quantity of high-pressure sodium and mercury vapor luminaires has been
steadily dropping over the past several years, the total number of LED luminaires
continues to increase in-kind due primarily to municipal driven conversion. Metal

		R. A. BELLINI
Line <u>No.</u>		U-21297
1		halide lighting luminaires represent approximately 1,400, or less than 1% of DTE
2		Electric's company owned lighting luminaires.
3		
4	Q14.	Can you provide an overview of the various lighting technologies for street
5		lights that are municipality owned (E1 Options II & III)?
6	A14.	The lighting for DTE Electric's E1 Option II Rate Schedule reflects a mix of 104
7		(75%) high pressure sodium lights and 34 (25%) mercury vapor lights. As I
8		previously indicated, this service has been closed to new customers since 2009, and
9		existing E1 Option II Rate Schedule customers electing to convert to LED are
10		required to convert to DTE Electric's E1 Option I or Option III Rate Schedules.
11		The mix of lighting for DTE Electric's E1 Option III Rate Schedule includes
12		approximately 70,000 (84%) LED luminaires, 12,000 (15%) high pressure sodium
13		luminaires, and the remainder consisting of MV and MH lighting. The high
14		concentration of energy-efficient LED lighting in this class reflects the City of
15		Detroit's conversion of most of its streetlights to LED.
16		
17	Q15.	Can you provide an overview of DTE Electric's Community Lighting D9 OPL,
18		E2 ATS, and E1.1 metered municipal-owned lights rate schedules?
19	A15.	DTE Electric's D9 OPL rate schedule and its proposed pricing reflects recovery of
20		costs associated with the ownership, maintenance and provision of energy to a
21		portfolio of approximately 24,000 commercial and 9,000 residential outdoor
22		protective lights. OPL lighting utilizes the same technologies as streetlighting and
23		consistent with conversions of failed mercury vapor streetlights to LED, the
24		Company began converting failed mercury vapor OPLs to LED starting in February
25		2017.

		R. A. BELLINI
Line <u>No.</u>		U-21297
1		
2		DTE Electric's E2 Rate Schedule and proposed pricing reflects the recovery of
3		costs for the production and distribution of energy for ATS lights owned and
4		maintained by municipalities and other public authorities.
5		DTE Electric also provides metered municipality-owned streetlight service under
6		the E1.1 Rate Schedule. I support the energy forecast for this Rate Schedule and
7		Witness Willis supports the proposed rate for this service.
8		
9	Com	nunity Lighting Sales Forecast
10	Q16.	How did you develop the sales forecast for Lighting?
11	A16.	Consistent with the methodology utilized in prior Company electric rate cases, the
12		sales forecast for the E1 Option I & II Rate Schedules were developed by first
13		preparing a forecast of light counts for each lighting type (technology and wattage
14		size) for the projected test period based upon: (1) known projects, (2) continued
15		conversions of mercury vapor lighting to LED lighting, and (3) an estimate of
16		increased light counts net of removals, resulting from sales growth. The system
17		wattage (nominal lamp wattage plus ballast wattage) applicable to each lighting
18		type was applied to the forecasted volume of lights for each lighting type. Annual
19		usage was assumed to be 4,200 hours, to reflect the hours that the lights on either
20		the dusk to dawn or standard provision are illuminated. The energy forecast for
21		lights on the dusk to midnight provision was based upon 2,100 hours use and the
22		energy forecast for lights on the de-energized provision is zero.
23		
24		The sales forecast for the E1 Option III Rate Schedule was developed by first
25		preparing a forecast of light counts for each of the lighting types for the projected

1		test period based upon known municipal-owned streetlighting projects and an
2		estimate of light count changes. The system wattage value applicable to each
3		lighting type was applied to the forecasted volume of lights for each lighting type
4		for the 4,200 hours for which all the lights are illuminated on an annual basis.
5		
6		The total sales forecast for the OPL D9 Rate Schedule, like that prepared for the E1
7		Rate Schedule, was developed by preparing a forecast of light counts for each of
8		the lighting types for the projected test period based upon existing light counts, an
9		estimate of increased light counts resulting from sales growth net of removals, and
10		continued conversion of mercury vapor lighting to LED lighting. The system
11		wattage value applicable to each lighting type was applied to the forecasted volume
12		of lights for each lighting type for the 4,200 hours for which the lights are
13		illuminated on an annual basis.
14		The sales forecast for the ATS E2 Rate Schedule was determined by using the total
15		connected wattage, as of November 2022, for the rate schedule and determining the
16		annual usage based upon that determinant. In other words, it is simply the product
17		of the total reported wattage and the total number of hours in the projected test
18		period.
19		
20		The total sales forecast for the E1.1 Rate Schedule was based upon annualized
21		usage data for the 12-month period that ended November 2022.
22		
23	<u>Comp</u>	any Preventative Maintenance Programs
24	Q17.	What preventative maintenance programs does the Company manage and
25		how are the related expenses classified?

A17.	The Company manages the following preventative maintenance programs: 1)
	Group Relamping, 2) LED Washing, 3) Post Inspections, 4) Post Painting, 5) Night
	Patrol, 6) Post Replacement, And 7) Cable Replacement. The Post and Cable
	Replacement programs are considered capital expenditures while the remaining
	programs are booked as O&M.
Q18.	Can you provide an overview of the LED Washing program?
A18.	The LED Washing and the HPS Group Relamping programs are intended to ensure
	lighting output is maintained at an appropriate level to provide for the safety and
	security of the public. Specific to LED's, DTE conducted two LED light loss factor
	(LLF) studies, one in 2015 and again in 2017, to determine how LED lumen output
	depreciated over time. The results of those studies identified the need to wash
	LED's on a periodic basis to ensure that their lumen output remained at or above
	L70 (70% of the initial lumen output), the level at which the Illuminating
	Engineering Society of North America (IESNA) has determined the LED would no
	longer function as a useful lighting source <sup>2</sup> . As a result, DTE implemented an LED
	washing program through which each fixture's optic lens is first cleaned with a soft
	bristle brush, and then washed with a microfiber cloth, dampened with a 50/50
	Isopropyl alcohol and water solution. Pursuant to the Commission order on
	November 18, 2022, in Case No. U-20836, DTE will adopt a 10-year LED washing
	cycle that will take effect in 2023.
	A17. Q18. A18.

22

## 23 Q19. Can you provide an overview of the HPS Group Relamping program?

<sup>&</sup>lt;sup>2</sup> Illuminating Engineering Society North America (IESNA) LM-80-08 "Approved Method for Measuring Lumen Maintenance of LED Light Sources"

1	A19.	Similar to the LED Washing program, the HPS Group Relamping program is
2		intended to maintain HPS lighting levels at or above L70 throughout the course of
3		the luminaire's useful life. The relamping process includes replacing the lamp as
4		well as cleaning the luminaire. By proactively relamping HPS luminaires on a 9-
5		year cycle, DTE is able to reduce its HPS maintenance costs as well as outages.
6		
7	Q20.	Was additional analysis required with respect to HPS Group Relamping as
8		part of the Commission Order in Case No. U-20836?
9	A20.	Page 483 of the Commission's order in Case No. U-20836 states that "In its next
10		general rate case, DTE Electric Company shall provide an updated analysis of its
11		streetlight <i>re-lamping policy</i> and wattage selection." Relamping will be discussed
12		below, while wattage selection will be discussed later in my testimony.
13		
14	Q21.	What is DTE providing to comply with the Commission requirement
15		regarding an updated analysis of its streetlight relamping policy?
16	A21.	DTE is providing 1) an overview of its relamping program that summarizes why a
17		9-year cadence is appropriate and reasonable, and 2) the formula and related results
18		of the Company's 2022 analysis based on 2021 lamp and labor cost data.
19		
20	Q22.	How did the Company determine that a 9-year HPS relamping cycle was
21		appropriate?
22	A22.	The only HPS lamp used in municipal settings is the Lumalux Plus which is
22 23	A22.	The only HPS lamp used in municipal settings is the Lumalux Plus which is manufactured by Sylvania. The Lumalux Plus specification sheet indicates 40,000
22 23 24	A22.	The only HPS lamp used in municipal settings is the Lumalux Plus which is manufactured by Sylvania. The Lumalux Plus specification sheet indicates 40,000 operating hours as its useful life. The annual burn rate of a lamp is 4,200 hours

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Line

lumen depreciation curve provided by the manufacturer shows that after 40,000
 hours of service, the lamp approaches 70% of the initial lumen output. To avoid
 having the HPS lumen output fall below 70%, the Company established 9 years as
 the optimal cadence for relamping.
 **Q23.** Has DTE Electric performed an analysis that demonstrates group relamping

7 of HPS lamps has resulted in cost savings?

A23. Yes, DTE updated its' study in 2022 that demonstrates cost savings associated with
proactive group relamping vs spot relamping when responding to an outage. The
results of this study indicated a 53% cost savings per lamp when performing
proactive group relamping. The formula in Table 4 below was used to demonstrate
these savings:

Line No.		<b>R. A. BELLINI</b> U-21297
1		Table 4: HPS Group Relamping Cost Savings Formula
2		Coour Delemaine Deventative Maintenance
3		The following 2 formulas compare the cost-benefit of a planned, group relamping preventative maintenance (PM) program ( <b>Group Relamping Cost (Planned</b> )) for HPS luminaires (light sources) as compared to a non- planned, reactive HPS lamp replacement ( <b>Single Relamping Cost (Reactive</b> )) performed as part of an outage
4		event.
5		Formula Used to Calculate the Cost Benefits of a Group Relamping PM Program
6		B/A(C+G+(C*K*L)+(K*I)) B/R(C+I+M(C+I))
7		<ul> <li>B burning hours per year (4,200)</li> <li>R rated lamp life, hours (40,000)</li> <li>A burning time between group replacements (9 years)</li> </ul>
8		C net cost of the lamp I cost per lamp for a reactive single lamp replacement during a single outage event
9		<b>G</b> cost per lamp for a planned lamp replacement using the Group Relamping PM program <b>K</b> proportion of lamps failing before group replacement time
10		L the portion of the lamp cost of the early burnouts that are charged against group replacement (0) M proportion of lamps failing before rated end of life (50%)
11		DTE Electric Study Results Based on the above cost comparison DTE Electric would achieve a 53.4% reduction in reactive outage cost
12		through funding of a group relamping program for High Pressure Sodium (HPS) luminaires. Example: a \$100,000 annual cost to fund group relamping would compare to an annual \$214,512 outage cost if
13		no group relamping occurred, thus the annual group relamping program cost savings is \$114,513 = 53.4% (\$114,513 / \$214,512).
14		
15		
16	Q24.	You referenced earlier in your testimony the ongoing conversion from HID to
17		LED luminaires. What impact will this have on the HPS Group Relamping
18		program?
19	A24.	Due to the significant decline in HIDs over the past 7 years as a result of
20		municipality-driven conversions, the Company has determined that the program to
21		replace HPS lamps will become less cost effective assuming that the conversion
22		rate to LED's remains consistent. Therefore, the Company has decided to sunset
23		the HPS Group Relamping program at the end of 2023. DTE will continue to
24		replace failed HPS lamps like-for-like pursuant to our E1 Option I tariff as
25		identified through night patrols or as reported by municipalities.

line <u>Io.</u>		U-21297
1	Q25.	Please describe the Company's Post Inspection program and its relationship
2		to the Post Painting and Post Replacement programs.
3	A25.	DTE Electric owns more than 60,000 posts and has established detailed post
4		inspection criteria to inspect its posts every three years to both identify posts whose
5		structural integrity dictates their replacement (condemnation), and posts that
6		require painting. At the time posts are inspected, minor post maintenance work
7		such as adding or replacing post asset tags, post hand-hole covers, and T-box door
8		covers may also be completed.
9		
10		Over the past three years, DTE Electric's post inspection process has resulted in the
11		annual replacement of condemned posts at a rate of approximately 3% and post
12		painting at a rate of approximately 5% relative to the total population of posts.
13		
14	Q26.	Please describe the Company's Night Patrol program and its purpose.
15	A26.	To further bolster customer service and reliability, the Company in 2019
16		implemented a Night Patrol program with the intent to proactively identify
17		municipal-wide outages which would then be routed to a DTE authorized
18		construction crew for repair. All of DTE's E1 Option I streetlights are within the
19		scope of this program, and depending on prior patrol results and repair detail (i.e.

large percentage of outages noted in a single municipality or high concentration of 20 21 outages in a specific area), the Company may adjust the timing of the next scheduled night patrol. 22

#### 23 In 2022, DTE developed a night patrol database to record details by light and by 24 circuit as to the nature and recurrence of outages. The purpose of cataloging this

Line <u>No.</u>		<b>R. A. BELLINI</b> U-21297
1		data is to allow for the Company to utilize analytics to identify repeat visits to the
2		same luminaire or problematic circuits because of underground cable failures.
3		
4	Q27.	Why did the Company launch the Cable Replacement program which targets
5		underground cable replacements?
6	A27.	As more outage data continues to be collected from the Night Patrol program, we
7		are beginning to identify root cause issues through direct feedback from our
8		contractors tasked with restoring service, and data on specific lights and circuits
9		that indicate recurring outages. In general, outages are the result of 1) a failed
10		luminaire, 2) failed wiring or components such as a photocell, or 3) failed
11		underground cable.
12		
13		This program specifically targets underground cable replacement work as this tends
14		to be the most costly type of repair to perform on a reactive basis and has a higher
15		likelihood to impact several lights when the cable begins to fail. Repairing larger
16		stretches of cable using a data driven approach on a planned basis through this
17		program is not only a more cost effective, but we also anticipate it will reduce the
18		likelihood of one or more lights failing due to an underground fault once replaced,
19		thereby increasing reliability.
20		
21	Q28.	You mentioned that proactive underground cable replacement work is more
22		cost effective than reactive repairs. Can you elaborate?
23	A28.	When responding to outage events that involve underground cable failures as the
24		root cause, our repair crew's primary objective is to address the immediate issue

and restore service as quickly as possible. This increases the number of "locate and

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2

3

4

repairs" which result in sections of failed cable being isolated and replaced. Though this addresses the immediate root cause, it doesn't necessarily increase the longevity of the stretch of cable supporting that circuit, in a manner that replacing failed, or end-of-life underground cable would.

5

## Q29. Are there any other long-term benefits expected to be realized from the Cable Replacement program?

8 A29. First, most of the underground system cable that is currently in service is direct 9 buried, meaning that the cable is unsleeved and buried at a depth which makes it more susceptible to freezing and thawing impacts as well as 3<sup>rd</sup> party strikes during 10 11 excavation work (i.e. other utility work or municipal driven projects such as road 12 widening). Cable that is replaced under this program is now installed within a protective sleeve which increases the likelihood that it can survive a 3<sup>rd</sup> party strike 13 14 or become exposed through excavation. Second, as damaged and end-of-life cable 15 is replaced with newly installed and protected cable, we expect to see a reduction 16 in outages whose root cause is determined to be an underground cable failure. Over 17 time, this will reduce the number of reactive underground cable events and increase 18 lighting system reliability.

19

#### 20 Outage Restoration Activities

## Q30. What was DTE Electric's performance with respect to outage duration for its lighting customers?

A30. DTE Electric has several targets for outage performance: outage duration and
 outage defects. DTE Electric's 2021 outage duration target was 3.0 business days
 and DTE Electric's 2021 actual performance was 5.2 business days. These

1

2

3

historical metrics for outage duration and defects are displayed on Exhibit A-25, Schedule O1.

- 4 In addition to weather-related events, "long duration" and "follow-up" outage 5 events include extended repair time for underground faults (i.e. Miss Dig permits), 6 repairs resulting from third party damage, and lack of special order material (SOM) 7 maintained by a city or municipality. The performance metrics only include 8 reactive street light outage repairs; they do not include any outage repair resulting 9 from patrol and fix activities nor any preventative maintenance activities such as 10 group re-lamping. Street light outage events reported on weekends and after normal 11 week-day business hours are analyzed and dispatched to crews on the following 12 business day. DTE Electric measures both total and crew duration cycle repair 13 periods. Crews authorized by DTE Electric work to complete reactive outage 14 repairs of reported street light outage events.
- 15

## Q31. What other measures does DTE Electric have in place to improve its restoration time and to maintain a high level of customer service?

18 A31. DTE Electric has established strategic maintenance contracts with the contractors 19 performing the outage restoration work to include financial penalties for not 20 achieving targeted restoration times. Restoration performance, among other 21 metrics, is reviewed with the contractors at monthly performance meetings and, to 22 the extent that restoration performance is not meeting expectations, DTE Electric 23 can shift responsibility for restoration in certain service territories to alternative 24 contractors to achieve the desired restoration performance. Internally, the 25 Company evaluates contractor performance metrics on a weekly basis to identify

10.		
1		potential performance issues or problem-solving opportunities. In addition to these
2		efforts, the Company continues to improve the arrangements for the provision of
3		special-order materials on behalf of municipalities that choose streetlight materials
4		that are not included in DTE Electric's standard streetlight offerings.
5		
6	Q32.	What was Community Lighting's spend with respect to outage restoration
7		activity?
8	A32.	In 2021, DTE Electric's Community Lighting team spent approximately \$7.6
9		million on outage restoration expense with approximately 63% of this cost being
10		capitalized, and the balance being recorded as O&M. The outage restoration
11		expense was approximately \$6.3 million in 2020. Exhibit A-25, Schedule O2
12		reflects DTE Electric's historical performance for outage restoration cost per event.
13		
14	Q33.	Please explain the difference between capitalized outage expenses and non-
15		capitalized, or O&M outage expenses.
16	A33.	Outage restoration activities include remediating identified lighting outages that
17		could range from replacement of small wiring or lighting components to
18		replacement of system cable, posts, and luminaires. Any repair (inclusive of both
19		materials and labor) that does not extend the useful life of the lighting asset (small
20		wiring or lighting components such as a replacement of a photocell) is considered
21		an O&M expense. All other repairs (both materials and labor) are considered
22 23		capital expenditures.
Line <u>No.</u>

1	Comm	nunity Lighting Operations & Maintenance and Capital Expenditures
2	Q34.	What is included in the Operations & Maintenance of Street Lighting and
3		Signal Systems account on line 23 of Exhibit A-13, Schedule C5.6, page 1?
4	A34.	Line 23 on this exhibit show the projected O&M expenses which are directly
5		assigned to Account 596, Maintenance of Street Lighting and Signal Systems. This
6		account represents preventive maintenance expense, labor expense and non-
7		capitalized outage restoration expense. The preventive maintenance work included
8		post inspection, post painting, re-lamping high pressure sodium luminaires, and
9		night patrols for DTE owned municipal streetlights. The labor expense primarily
10		reflects the labor of the Community Lighting team including sales, planning, asset
11		maintenance, construction and asset engineering. As reflected on Exhibit A-13,
12		Schedule C5.6, the historical period O&M expense of \$5.2 million is adjusted for
13		inflation of 3.60% for 2022, 3.20% for 2023, and 2.66% for the first 11 months of
14		2024. This results in a forecasted O&M expense of \$5.7 million in the projected
15		test period.
16		
17	Q35.	What are the Community Lighting capital expenditures on Exhibit A-12,
18		Schedule B5.5, "Projected Capital Expenditures – Community Lighting"?
19	A35.	Capital expenditures for Community Lighting for 2021 were \$14.8 million. The
20		2021 expenditures included approximately \$7.0 million for new installations and
21		replacements, \$4.8 million for outage restoration, \$1.7 million for post
22		replacements, and \$1.3 million for planned HID to LED conversions.
23		
24		The projected capital expenditures for Community Lighting are \$17.3 million for
25		2022, \$15.4 million for 11 months ending November 30, 2023, and \$16.7 million

#### RAB-21

1		for 12 months ending November 30, 2024. Similar to the 2021 actual expenditures,
2		these projections include outage restoration, including conversion of failed mercury
3		vapor luminaires to LED for both streetlight and OPLs, post replacement, new
4		business, and capital support staff. As previously discussed, Community Lighting
5		launched its underground cable replacement program in 2022 and is also included
6		in Exhibit A-12, Schedule B5.5 line 4 with projected spend of \$1.4 million for 2022,
7		\$1.1 million for 11 months ending November 30, 2023, and \$1.1 million for 12
8		months ending November 30, 2024.
9		
10	LED ]	Luminaire Selection Methodology
11	Q36.	Was additional analysis required with respect to its luminaire selection process
12		as part of the Commission Order in Case U-20836?
13	A36.	Yes. Page 483 of Commission Order U-20836 states that "In its next general rate
14		case, DTE Electric Company shall provide an updated analysis of its streetlight re-
15		lamping policy and <i>wattage selection</i> ."
16		
17	Q37.	What has DTE included in this case to address the requirement for an analysis
18		of its LED wattage selection process?
19	A37.	DTE is providing 1) an overview of the relative importance for selecting proper
20		roadway lighting, 2) the Company's evaluation criteria including design and
21		execution of lighting layouts, 3) the industry standards by which lighting layouts
22		are designed to, 4) Company selected luminaire types, and 5) luminaire cost
23		overview.
24		

Line No

#### **R. A. BELLINI** U-21297

# Q38. Could you explain the importance of selecting the appropriate luminaire when conducting roadway lighting analysis?

3 A38. The purpose of street lighting is to provide adequate light levels, uniformity, and 4 target contrast dependent on the road classification. Street lighting should support 5 the visual needs of a driver and a pedestrian under mesopic<sup>3</sup> roadway lighting 6 conditions. These provisions enhance a driver's visual acuity to detect hazards or 7 objects in the roadway or the surrounding area. They are paramount in providing 8 sufficient object detection distances for drivers to discern potential hazards in the 9 roadway, such as pedestrians, vehicles, and other objects during the nighttime 10 hours. It is also important to have appropriate target light levels at mid-block 11 crosswalks, intersection crosswalks, and the surrounding vicinity from the curb to 12 adjacent sidewalk area outside of the travel lanes while minimizing obtrusive light.

13

## Q39. How does DTE evaluate luminaire output to ensure it achieves (or maintains in the event of an HID to LED conversion) the proper level of illumination?

16 A39. DTE performs an in-depth photometric evaluation based on the effectiveness of a 17 roadway luminaire achieving pre-established, application-based photometric 18 requirements. These models are designed to evaluate the photometric performance 19 of new LED roadway luminaire(s) in comparison to an existing HID roadway 20 luminaire dependent to the road classification. Several models of various roadway 21 configurations are set up using the HID roadway luminaire as the control variable 22 in the comparative analysis process, resulting in various data points being 23 generated. These data points are then synthesized into an evaluation matrix for 24 analysis to rank the photometric performance of the test subject against the control

<sup>&</sup>lt;sup>3</sup> Mesopic vision, sometimes called twilight vision, is a combination of **photopic** and **scotopic vision** under low-light (but not necessarily dark) conditions.

Line <u>No.</u>		<b>R. A. BELLINI</b> U-21297
1		variable and the competition. The outcome of this analysis will determine whether
2		a new LED luminaire can achieve minimum roadway luminance and illuminance
3		target values that complies with ANSI/IES RP-8 <sup>4</sup> standards.
4		
5	Q40.	Can you explain what is ANSI/IES RP-8 standards, and why these standards
6		are used in in determining luminaire selections?
7	A40.	The Illuminating Engineering Society (IES) is a non-profit, independent society
8		that is internationally recognized by lighting industry professionals consisting of
9		lighting engineers, lighting designers, lighting manufacturers, consultants,
10		academics, and scientists. IES Recommended Practice (RP) standards and Design
11		Guides (DG) are developed and published through the American National Standard
12		Institute (ANSI) accredited process using a consensus of select IES committee
13		members that specialize in the intended lighting application. The ANSI/IES RP-8
14		"Recommended Practice: Lighting Roadway and Parking Facilities" publication is
15		the street lighting and parking lot lighting standard intended for lighting engineers,
16		lighting designers, and specifiers. ANSI/IES RP-8 is the benchmark in roadway
17		lighting design practices used in street lighting to evaluate and select new roadway
18		luminaire products.
19		
20	Q41.	Can the LED luminaires selected to replace HPS luminaires as part of DTE's

21

### photometric design analysis deviate from those suggested by a manufacturer?

A41. Yes, particularly in the case of DTE's primary roadway luminaire vendor, Leotek.
Leotek has published a cross-over chart (see Exhibit A-25, Schedule O3 "HID-to-

<sup>&</sup>lt;sup>4</sup> DTE uses the most current IES-RP-8-XX "Recommended Practice: Lighting Roadway and Parking Facilities" publication for each photometric evaluation conducted.

Line No.

> 1 GreenCobra-4000K-Crossover-Chart") for customers to use as a starting point in 2 evaluating the appropriate LED luminaire selection when converting from an 3 equivalent HPS luminaire. This cross-over chart provides three lighting level 4 outputs (high / medium / low) under the column "Light Levels" for each HPS 5 luminaire lumen output range being converted to an equivalent LED lumen output 6 range. The column titled "Lumen Output" indicates Leotek LED luminaire initial 7 delivered lumens associated with each of the HPS luminaire lighting levels. The 8 objective of this chart is to match new "out of the box" Leotek LED luminaires with 9 their initial light levels to existing HPS luminaires in the field for several years 10 using high, medium, and low light levels. In other words, the conversion table is 11 designed to replace an HPS luminaire at its current lumen output, not its original 12 lumen output. This would result in a lower wattage LED with lower light levels 13 being selected to match the performance of an older HPS luminaire with 14 depreciated (degraded) lumen output.

15

16 To illustrate this point, a 100-watt "out of the box" HPS luminaire has a lumen 17 output of 9,500 initial delivered lumens. However, the conversion chart shows 18 derated lumen values from 4,299 (low) to 5,883 (high), which is significantly lower 19 than its original output. This is akin to replacing a set of tires on a vehicle that have 20 reached the end of their life, with a set of new tires whose tread is equal to the tread 21 of those that were replaced. The Company's objective is to restore equivalent "out 22 of the box" lumen output of the luminaire being replaced to match the intended 23 lighting design of the original streetlighting system.

#### Line No.

#### 1 <u>Community Lighting Rate Design</u>

#### 2 Q42. What does Exhibit A-16, Schedule F3 show?

3 A42. This exhibit shows the present and proposed rate design and corresponding 4 revenues by rate schedule, based on the billing determinants for the 12 months 5 ending November 30, 2024. The exhibit details the forecasted billing determinants 6 as well as the resulting present and proposed rates and revenues. The various billing 7 components are listed in column (a), and the respective billing determinants, 8 including units of measure, are listed in column (b). The forecasted billing 9 determinants were developed based on historical data and relationships, as well as 10 known and measurable changes, and are consistent with the sales forecast as 11 presented on Company Witness Mr. Leuker's Exhibit A-15, Schedule E1, Other 12 class sales. The existing luminaire and energy rates, both non-capacity energy and 13 capacity energy, as approved in the Order dated November 18, 2022, in Case No. 14 U-20836 are in columns (c), (d) and (e), and are used to calculate the present 15 revenues in column (f). The luminaire rates proposed in this proceeding based upon 16 the lighting cost of service (as discussed in detail below) are in column (g), the 17 proposed non-capacity energy rates are in column (h), the proposed capacity energy 18 rates are in column (i) and the resulting revenues from the new lighting cost of 19 service are in column (j).

20

## Q43. How were DTE Electric's present Municipal Street Lighting and Outdoor Protective Lighting charges determined?

A43. The lighting rates approved in MPSC Case No. U-20836 reflect a monthly energy
 charge, both non-capacity energy and capacity energy, and a luminaire charge. The
 monthly energy charge was determined by applying the energy rates, both in

Line <u>No.</u>

25

1		cent/kWh, to the calculated consumption values of the various lighting technology
2		lamp sizes for both the E1 and D9 Rate Schedules. The luminaire charge is a fixed
3		monthly amount applied to each luminaire dependent on the technology utilized,
4		the lamp size or wattage, the lighting provision and whether it is served from
5		underground or overhead. The total (energy and luminaire) monthly lighting
6		charges that were calculated in MPSC Case No. U-20836 do not fully represent true
7		cost of service rates by technology type (within the lighting rate class). In MPSC
8		Case No. U-20836, the lighting rates were gradually moved towards cost of service,
9		with the total movement capped to minimize the impact on any individual customer.
10		
11	Q44.	What is the allocation methodology for production and distribution revenue
12		requirements to the various lighting rate schedules that you are supporting in
13		this case?
13 14	A44.	this case? The functionalized production (Exhibit A-16, Schedule F1.1) and distribution
13 14 15	A44.	<ul><li>this case?</li><li>The functionalized production (Exhibit A-16, Schedule F1.1) and distribution</li><li>(Exhibit A-16, Schedule F1.2) revenue requirement amounts supported by</li></ul>
13 14 15 16	A44.	<ul><li>this case?</li><li>The functionalized production (Exhibit A-16, Schedule F1.1) and distribution</li><li>(Exhibit A-16, Schedule F1.2) revenue requirement amounts supported by</li><li>Company Witness Maroun for each of the lighting rates schedules (D9, E1, &amp; E2)</li></ul>
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> </ol>	A44.	<ul><li>this case?</li><li>The functionalized production (Exhibit A-16, Schedule F1.1) and distribution</li><li>(Exhibit A-16, Schedule F1.2) revenue requirement amounts supported by</li><li>Company Witness Maroun for each of the lighting rates schedules (D9, E1, &amp; E2)</li><li>were fully allocated to each of those rate schedules within the lighting rate model.</li></ul>
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> </ol>	A44.	<ul> <li>this case?</li> <li>The functionalized production (Exhibit A-16, Schedule F1.1) and distribution (Exhibit A-16, Schedule F1.2) revenue requirement amounts supported by Company Witness Maroun for each of the lighting rates schedules (D9, E1, &amp; E2) were fully allocated to each of those rate schedules within the lighting rate model.</li> <li>The proposed luminaire, distribution, and energy charges (both capacity and non-</li> </ul>
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> </ol>	A44.	this case? The functionalized production (Exhibit A-16, Schedule F1.1) and distribution (Exhibit A-16, Schedule F1.2) revenue requirement amounts supported by Company Witness Maroun for each of the lighting rates schedules (D9, E1, & E2) were fully allocated to each of those rate schedules within the lighting rate model. The proposed luminaire, distribution, and energy charges (both capacity and non- capacity) within each of the rate schedules were designed to meet the production
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> </ol>	A44.	this case? The functionalized production (Exhibit A-16, Schedule F1.1) and distribution (Exhibit A-16, Schedule F1.2) revenue requirement amounts supported by Company Witness Maroun for each of the lighting rates schedules (D9, E1, & E2) were fully allocated to each of those rate schedules within the lighting rate model. The proposed luminaire, distribution, and energy charges (both capacity and non- capacity) within each of the rate schedules were designed to meet the production and distribution revenue requirement for each rate schedule shown in these exhibits.
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> </ol>	A44.	this case? The functionalized production (Exhibit A-16, Schedule F1.1) and distribution (Exhibit A-16, Schedule F1.2) revenue requirement amounts supported by Company Witness Maroun for each of the lighting rates schedules (D9, E1, & E2) were fully allocated to each of those rate schedules within the lighting rate model. The proposed luminaire, distribution, and energy charges (both capacity and non- capacity) within each of the rate schedules were designed to meet the production and distribution revenue requirement for each rate schedule shown in these exhibits. Witness Maroun's Exhibit A-16, Schedule F1.5, detailing how much of the
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> </ol>	A44.	this case? The functionalized production (Exhibit A-16, Schedule F1.1) and distribution (Exhibit A-16, Schedule F1.2) revenue requirement amounts supported by Company Witness Maroun for each of the lighting rates schedules (D9, E1, & E2) were fully allocated to each of those rate schedules within the lighting rate model. The proposed luminaire, distribution, and energy charges (both capacity and non- capacity) within each of the rate schedules were designed to meet the production and distribution revenue requirement for each rate schedule shown in these exhibits. Witness Maroun's Exhibit A-16, Schedule F1.5, detailing how much of the production revenue requirement for each rate class is capacity and non-capacity
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>23</li> </ol>	A44.	this case? The functionalized production (Exhibit A-16, Schedule F1.1) and distribution (Exhibit A-16, Schedule F1.2) revenue requirement amounts supported by Company Witness Maroun for each of the lighting rates schedules (D9, E1, & E2) were fully allocated to each of those rate schedules within the lighting rate model. The proposed luminaire, distribution, and energy charges (both capacity and non- capacity) within each of the rate schedules were designed to meet the production and distribution revenue requirement for each rate schedule shown in these exhibits. Witness Maroun's Exhibit A-16, Schedule F1.5, detailing how much of the production revenue requirement for each rate class is capacity and non-capacity related, was used to allocate the production revenue requirement between the

charges, both capacity and non-capacity, were developed based upon the total

Line <u>No.</u>		<b>R. A. BELLINI</b> U-21297
1		production revenue requirement prepared by Witness Maroun for the E1 and D9
2		Rate Schedules.
3		
4	Rate S	Schedule E1
5	Q45.	How were the proposed E1 Rate Schedule luminaire charges determined?
6	A45.	The Company determined the new luminaire service cost structures listed in the E1
7		Rate Schedule tariff schedules as shown on Exhibit A-16, Schedule F3 by
8		reviewing and allocating the specific cost of service components to the type of
9		service, underground or overhead, and then further allocating them to the individual
10		lighting technologies. There were no changes in the methodology for the allocation
11		of non-production O&M costs or capital-related costs to luminaire charges
12		proposed in this proceeding.
13		
14	Q46.	How was O&M allocated to the proposed E1 Rate Schedule luminaire charges
15		in the lighting model?
16	A46.	Total Distribution O&M expense reflected in the E1 Rate Schedule luminaire
17		charge is \$11.1 million, based upon the Company's cost of service model sponsored
18		by Witness Maroun. This distribution O&M expense is comprised \$4.7 million
19		directly assigned to lighting and recorded in account 596 (Street Lights & OPL),
20		\$3.3 million allocated to lighting from various distribution operation and
21		distribution maintenance accounts, \$1.4 million from various customer
22		service/sales accounts allocated to E1 Rate Schedule lighting and \$1.7 million of
23		total A&G expense. Based upon the underlying labor costs within account 596 and
24		the various distribution operation, distribution maintenance and customer service
25		accounts allocated to E1 Rate Schedule lighting, approximately 42%, or \$0.7

	U-21297
	million, of A&G expense was directly allocated to E1 Option I Rate Schedule
	lighting and the balance was allocated to the various distribution O&M accounts
	within the E1 Rate Schedule.
	The total customer service and distribution O&M expense allocated to lighting,
	including A&G allocated to these accounts, was further allocated to the various E1
	Rate Schedule luminaire/distribution charges based upon the system wattage of the
	luminaires and lamps. With the exception of group re-lamping, LED washing, post
	inspection, night patrols and post painting, all O&M ( $$4.7$ million) and A&G ( $$0.7$
	million) directly assigned to lighting was spread equally across all luminaires. The
	O&M associated with LED washing was allocated to LED luminaires (both
	overhead-fed and underground-fed) based upon the underlying LED saturation and
	contract cost, O&M associated with post inspection and post painting was spread
	equally to all underground fed luminaires and O&M for group re-lamping was
	allocated to HPS luminaires only.
Q47.	How was depreciation expense allocated to the proposed E1 Option I Rate
	Schedule luminaire charges in the lighting model?
A47.	The total depreciation expense reflected in the E1 Option I Rate Schedule luminaire
	charges, as established in the Company's cost of service model supported by
	Witness Maroun, is \$26.9 million. This reflects \$19.4 million depreciation for the
	directly assigned lighting asset accounts, \$2.6 million for the distribution asset
	accounts allocated to lighting, and the balance associated with general and
	intangible plant accounts allocated to lighting.

**R. A. BELLINI** 

Line No.

Line <u>No.</u>

1	The depreciation expense for overhead subaccount 373.01 (street lighting and
2	signal systems - overhead) was allocated directly to overhead fed luminaires, and
3	depreciation expense for underground subaccount 373.02 (street lighting and signal
4	systems – underground) was allocated directly to underground fed luminaires. The
5	depreciation expense for overhead subaccount 373.03 (Street Lighting wire - OH)
6	was allocated to all overhead luminaires equally. The depreciation expense for
7	underground subaccount 373.04 (Street Lighting Wire/Cable - Underground) was
8	allocated to all underground-fed luminaires equally.
9	

10 The depreciation expense for both the overhead and underground luminaire 11 subaccounts (LED Overhead, LED Underground, and HID Overhead, HID 12 Underground) was allocated to the respective overhead and underground 13 luminaires based upon lighting technology, wattage and underlying original 14 investment. For instance, all underground-fed mercury vapor luminaires received 15 an allocation of depreciation expense from subaccount 373.05 (Street Lighting 16 Luminaires – HID Underground) based upon the luminaire type's investment and 17 underlying mercury vapor luminaire useful life.

18

19 The depreciation expense that was allocated to lighting from distribution was 20 allocated to all underground and overhead lighting based upon each luminaire 21 type's system wattage -- the best representation of each lighting type's usage of the 22 distribution system.

10.		
1	Q48.	How was the revenue requirement for other taxes, return on investment and
2		income tax allocated to the proposed E1 Option I Rate Schedule luminaire
3		charges?
4	A48.	All other components were allocated to the various luminaire types in a manner
5		similar to that employed for the related underlying depreciation expense. For the
6		directly assigned street lighting asset subaccounts, other taxes, return on investment
7		and income tax followed the allocation of net plant to each of the lighting types.
8		
9	Q49.	Do you believe the proposed allocation of costs reflected in the various E1
10		<b>Option I Rate Schedule luminaire charges is reasonable?</b>
11	A49.	Yes. The methodology utilized in the lighting model to allocate each of the
12		individual cost of service components discretely, rather than in total, more
13		accurately reflects the cost to provide lighting service to underground and overhead
14		assets as well as the various lighting technologies. The usage of the eight separate
15		asset subaccounts for allocation of the capital-related costs results in more accurate
16		rate setting based upon both how the lights are fed as well as the lighting
17		technology, wattage and luminaire investment.
18		
19	Q50.	How were the E1 Option II Rate Schedule charges developed?
20	A50.	The E1 Option II Rate Schedule charges were developed based upon a share of the
21		production revenue requirement allocated by Witness Maroun in the Company's
22		cost of service model to the E1 Rate Schedule, a share of the distribution and
23		customer service revenue requirements allocated by Witness Maroun in the
24		Company's cost of service model to the E1 Rate Schedule and a small allocation of
25		the O&M expense directly assigned to the E1 Rate Schedule from Account 596.

#### RAB-31

1 The allocations of revenue requirement from production, distribution and customer 2 service to the E1 Option II Rate Schedule were accomplished on a per kWh basis 3 across all E1 Option II rates. The proposed rates for the E1 Option II Rate Schedule 4 are displayed in a luminaire charge, similar to that for Rate Schedule E1 Option I, 5 and energy charges, both capacity and non-capacity, in a cent/kWh format. 6 7 Q51. How were the E1 Option III Rate Schedule charges developed? 8 A51. The E1 Option III Rate Schedule charges were developed based upon a share of the 9 total production revenue requirement allocated by Witness Maroun in the 10 Company's cost of service model to the El Rate Schedule, a share of the total 11 distribution revenue requirement allocated by Witness Maroun in the Company's 12 cost of service model to the E1 Rate Schedule and a share of the customer service 13 revenue requirement allocated by Witness Maroun in the Company's cost of service 14 model to the E1 Rate Schedule. The allocations of revenue requirement from 15 production, distribution and customer service to the E1 Option III Rate Schedule 16 were performed on an equal energy basis across all E1 Option III rates. The 17 proposed E1 Option III Rate Schedule distribution and energy charges, both 18 capacity and non-capacity, are displayed in a cent per kWh format, allowing for a 19 transparent comparison of lighting costs for the various luminaire system wattages 20 and the various lighting technologies.

21

Q52. How does your proposed cost allocation methodology impact the present rates
for the E1 Rate Schedule?

A52. The cost allocation methodology described above and employed in the lighting
model reflects a collective revenue deficiency for the E1 Rate Schedule options.

1	Q53.	What is your proposal regarding rate design in this proceeding for Rate
2		Schedule E1 Option I rates?
3	A53.	I have proposed a continuation of the gradual move towards rates which are entirely
4		based upon cost of service for the lighting class. Consensus on this methodology
5		was reached in the lighting collaborative ordered in Case No. U-17767 and
6		beginning with rate Case No. U-18014, the Rate Schedule E1 Option I lighting rates
7		are being gradually moved to rates which are entirely based upon cost of service.
8		
9	Q54.	How were the Rate Schedule E1 Option I proposed rates developed in this
10		proceeding?
11	A54.	The proposed Rate Schedule E1 Option I lighting rates were designed with two
12		goals in mind; (1) continue the gradual move to rates which are entirely cost based
13		and (2) minimize the impact of the proposed lighting rates on the monthly lighting
14		bill for any municipality. Using the lighting rate model, the first step towards
15		achievement of these goals was to limit the overall increase on any municipality
16		and/or total lighting rate to 1.5 times the proposed average increase in revenue
17		requirement. The second step of the process was to allocate the remaining revenue
18		deficiency for the Rate Schedule E1 Option I class, on a percentage basis, to all the
19		remaining lights.
20		
21	Rate S	Schedule D9
22	Q55.	How were the proposed rates for the D9 Rate Schedule determined?

A55. The proposed luminaire rates for the D9 Rate Schedule for both commercial and
 residential OPL service were developed based upon the allocated and directly
 assigned distribution costs supported by Witness Maroun in the Company's cost of

Line <u>No.</u>

1		service model. The luminaire rate design methodology employed in the lighting
2		model for the D9 Rate Schedule mirrors the methodology employed for the E1 Rate
3		Schedule with all allocated distribution costs assigned to luminaire charges based
4		upon energy consumption and the directly assigned costs allocated based upon the
5		underlying individual cost of service components. As I discussed earlier, the
6		proposed energy charges, both capacity and non-capacity, for the D9 Rate Schedule
7		for both commercial and residential OPL service were developed collectively with
8		the E1 Rate Schedule energy charges.
9		
10	Q56.	Are all of the proposed luminaire rates for the D9 Rate Schedule entirely cost-
11		based?
12	A56.	No. The proposed rates for Rate Schedule D9 required the use of the same two-
13		step methodology to gradually achieve cost-based intra-class rates that was

- 14 employed for the E1 Option I Rate Schedule.
- 15

#### 16 Rate Schedule E2

#### 17 Q57. How were the proposed Rate Schedule E2 charges determined?

A57. The Rate Schedule E2 charges were developed based upon the production, both
capacity and non-capacity, and distribution revenue requirements allocated to Rate
Schedule E2 customers by Witness Maroun in the Company's cost of service
model. Each of the revenue requirement amounts were divided by the total
forecasted energy for the projected test period to arrive at a distribution rate, a noncapacity energy rate and a capacity energy rate in cents/kWh.

.ine <u>Io.</u>		<b>R. A. BELLINI</b> U-21297
1	Q58.	How has Witness Maroun's presentation of the revenue deficiency for
2		production presented in this case impacted your rate design?
3	A58.	To allocate the targets to the lighting tariff energy charges, both capacity and non-
4		capacity, in the cost of service-based rate presentation, I have allocated the revenue
5		deficiency for Rate Schedule E2 to the E2 rate directly and I have allocated the total
6		D9 deficiency, and total E1 deficiency Rate Schedules to those energy rates in total.
7		
8	Q59.	Will you please describe Exhibit A-16, Schedule F8?
9	A59.	This exhibit contains the proposed tariff sheet changes which result from the pricing
10		changes described above.
11		
12	Q60.	Does this complete your direct testimony?
13	A60.	Yes, it does.

#### **STATE OF MICHIGAN**

#### **BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

In the matter of the Application of	)
DTE ELECTRIC COMPANY	)
for authority to increase its rates, amend	)
its rate schedules and rules governing the	)
distribution and supply of electric energy, and	)
for miscellaneous accounting authority.	)

Case No. U-21297

#### QUALIFICATIONS

#### AND

#### DIRECT TESTIMONY

#### OF

#### SHAWN D. BURGDORF

#### DTE ELECTRIC COMPANY QUALIFICATIONS AND DIRECT TESTIMONY OF SHAWN D. BURGDORF

Line <u>No.</u>

1	Q1.	What is your name, business address and by whom are you employed?
2	A1.	My name is Shawn D. Burgdorf. My business address is 8001 Haggerty Road,
3		Suite 109, Belleville, Michigan 48111. I am employed by DTE Electric Company
4		(DTE Electric or Company) as the Manager of the Power Supply Strategy &
5		Modeling team within the Generation Optimization department.
6		
7	Q2.	On whose behalf are you testifying?
8	A2.	I am testifying on behalf of DTE Electric.
9		
10	Q3.	What is your educational background?
11	A3.	I received a Bachelor of Science Degree in Mechanical Engineering from
12		University of Michigan in 2005. I also received a Master of Business
13		Administration Degree from Eastern Michigan University in 2016.
14		
15	Q4.	What is your work experience?
16	A4.	After receiving my Bachelor's degree from the University of Michigan in 2005, I
17		was employed by Consumers Energy Company (Consumers Energy). During my
18		initial employment at Consumers Energy, I worked in their production cost
19		modeling group where I supported the development of power supply forecasts using
20		the PROMOD® model as the basis. In 2009, I transferred positions into the
21		Transmission and Regulatory Strategies Department. In this role, I was responsible
22		for monitoring and analyzing filings by the Midcontinent Independent System
23		Operator, Inc. (MISO) at the Federal Energy Regulatory Commission (FERC). I
24		was also responsible for forecasting future transmission and certain energy market-

<u>lo.</u>		
1		related costs in Power Supply Cost Recovery (PSCR) proceedings before the
2		Michigan Public Service Commission (Commission or MPSC).
3		
4		In 2012, I began my employment at DTE Electric within the Generation
5		Optimization Department. In 2015, I was promoted to a Supervisor position and
6		subsequently in October 2018, I was promoted to my current Manager position
7		within Generation Optimization.
8		
9	Q5.	Do you hold any certifications or are you a member of any professional
10		organizations?
11	A5.	Yes. I have attended Utility Rate School and the Advanced Regulatory Studies
12		Program, both hosted by the National Association of Regulatory Utility
13		Commissioners (NARUC) and The Institute of Public Utilities Michigan State
14		University.
15		
16	Q6.	What are your current duties and responsibilities?
17	A6.	My current responsibilities include acquisition of wholesale electric power supply
18		to reliably and economically serve the energy requirements of the Company's
19		customers including: optimization of the Company's generation assets, including
20		renewable energy facilities, within the wholesale power market; management of
21		emission allowance procurement; management of resource adequacy processes;
22		modeling the DTE Electric generation fleet; optimizing financial transmission
23		rights; and review and advocacy of Company recommendations regarding proposed
24		MISO rules, regulations, and business practices.

Line
<u>No.</u>

1	Q7.	Have you pr	reviously sponsored testimony before the Michigan Public Service
2		Commission	(MPSC or Commission)?
3	A7.	Yes. I have s	sponsored testimony in the following MPSC cases:
4		U-16149	Consumers Energy's 2010-2011 Gas Cost Recovery (GCR) Plan
5		U-16485	Consumers Energy's 2011-2012 GCR Plan
6		U-16924	Consumers Energy's 2012-2013 GCR Plan
7		U-16890	Consumers Energy's 2012 PSCR Plan
8		U-17097-R	DTE Electric's 2013 PSCR Reconciliation
9		U-17319-R	DTE Electric's 2014 PSCR Reconciliation
10		U-17632	DTE Electric's 2013 Renewable Energy Plan Reconciliation
11		U-17680	DTE Electric's 2015 PSCR Plan
12		U-17793	DTE Electric's 2015 Amended Renewable Energy Plan
13		U-17804	DTE Electric's 2014 Renewable Energy Plan Reconciliation
14		U-17920	DTE Electric's 2016 PSCR Plan
15		U-17680-R	DTE Electric's 2015 PSCR Reconciliation
16		U-18111	DTE Electric's 2016 Amended Renewable Energy Plan
17		U-18082	DTE Electric's 2015 Renewable Energy Plan Reconciliation
18		U-18143	DTE Electric's 2017 PSCR Plan
19		U-17920-R	DTE Electric's 2016 PSCR Reconciliation
20		U-20069	DTE Electric's 2017 PSCR Reconciliation
21		U-20221	DTE Electric's 2019 PSCR Plan
22		U-20471	DTE Electric's 2019 Integrated Resource Plan (IRP)
23		U-20561	DTE Electric's 2019 Main Rate Case
24		U-20528	DTE Electric's 2020 PSCR Reconciliation
25		U-18091	DTE Electric's 2021 PURPA Avoided Cost

Line <u>No.</u>			<b>S. D. BURGDORF</b> U-21297
1	U-20836	DTE Electric's 2022 Main Rate Case	
2	U-21193	DTE Electric's 2022 IRP	

Line
<u>No.</u>

1	<u>Purp</u>	ose of Testimony
2	Q8.	What is the purpose of your testimony in this proceeding?
3	A8.	The purpose of my testimony is to establish the projected wholesale market energy
4		sales revenue net of fuel including the reconciliation of costs in 2021. To do this,
5		I projected capacity-related generation costs in the 2023 PSCR Plan (Case No. U-
6		21259), projected 2024 wholesale market revenues from energy and ancillary
7		services sales from the Company's capacity resources, and the fuel related cost
8		associated with the Company's capacity resources. This information is used by
9		Company Witness Mr. Maroun in his calculation of cost of service.
10		
11	Q9.	Are you sponsoring any exhibits in this proceeding?

12 A9. Yes. I am sponsoring the following exhibits:

13		<u>Exhibit</u>	<u>Schedule</u>	<u>Descriptio</u>	<u>n</u>			
14		A-26	P1	Projected	2024	4 PU	JRPA	Capacity-Related
15				Generation	n Cost			
16		A-26	P2	Projected	2024	PA295	/PA342	Capacity-Related
17				Generation	n Cost			
18		A-26	P3	Projected 2	2024 Ca	apacity-	Related (	Generation Cost &
19				Energy Sa	les Rev	venue N	let of Fu	el Cost Including
20				2021 Reco	onciliati	on		
21		A-26	P4	2021 Ener	gy Sale	s Reven	ue Net o	f Fuel
22								
23	Q10.	Were these e	xhibits prepar	ed by you o	or unde	er your (	direction	1?

A10. Yes, they were.

1	Q11.	Section 6w(3)(A) of Act 341 requires that for rate design purposes the capacity
2		charge include capacity-related generation costs in the Company's PSCR
3		mechanism. What are the capacity-related generation costs included in the
4		Company's PSCR mechanism?
5	A11.	The Company's PSCR mechanism includes capacity-related generation costs
6		associated with Public Utility Regulatory Policies Act of 1978 (PURPA) power
7		purchase agreements, PA295/PA342 Company-owned renewable energy systems,
8		PA295/PA342 renewable energy contracts, and capacity purchases.
9		
10	Q12.	How did the Company project the 2024 capacity-related generation costs for
11		PURPA power purchase agreements as included in its PSCR plan filing in
12		Case No. U-21259?
13	A12.	The Company's PURPA contracts have three rate components: fixed, operation and
14		maintenance (O&M), and variable. The projections for both the fixed and O&M
15		components were included in the capacity-related generation costs. The total
16		projected 2024 PURPA capacity-related generation cost is \$10.0 million as shown
17		on Exhibit A-26, Schedule P1, line 13.
18		
19	Q13.	What costs associated with PA295/PA342 Company-owned renewable energy
20		systems and power purchase agreements are included in the PSCR?
21	A13.	The portion of the cost of PA295/PA342 Company-owned renewable energy
22		systems that is passed through the PSCR Transfer Price mechanism is the approved
23		Transfer Price Schedule or the levelized cost of energy for the renewable energy
24		systems. The portion of the cost of PA295/PA342 power purchase agreements (i.e.,
25		non-Company owned) that is passed through the PSCR mechanism is the lower of

Line No. 1 the Transfer Price approved for the power purchase agreement and the contract 2 price of the agreement. 3 4 The Transfer Price is a proxy for the incremental non-renewable capacity and 5 energy expense that would be passed on to the customer if the renewable energy 6 resource was not developed. The relevant statute explains that when setting the 7 Transfer Price, the Commission shall consider factors including, but not limited to, 8 projected capacity, energy, maintenance, and operating costs, information filed 9 under Section 6j of 1939 PA 3 (MCL 460.6j), and wholesale market data including, 10 but not limited to, locational marginal pricing. 11 12 Q14. How did the Company project the 2024 capacity-related generation costs for 13 PA295/PA342 company-owned renewable energy systems and power purchase 14 agreements? 15 A14. The capacity-related generation cost for PA295/PA342 Company-owned and non-16 Company-owned renewable energy systems and power purchase agreements is the

- approved Transfer Price fixed component for each specific renewable energy system. The total projected 2024 PA295/PA342 capacity-related generation cost is
- 19 \$130 million as shown on Exhibit A-26, Schedule P2, line 39.
- 20

17

18

#### 21 Q15. How did the Company project the 2024 cost of capacity purchases?

22 A15. The Company included the net capacity purchase costs based on the 2023 PSCR 23 Plan (Case No. U-21259) forecasted expense for the calendar year 2024. The 24 expense includes the Company's net transactions within the MISO annual Planning 1

2

Resource Auctions (PRA) covering the 2024 calendar year<sup>1</sup>. Consistent with the amount filed in Case No. U-21259, the total projected cost of capacity purchases is 3 \$(18.6) million as shown on Exhibit A-26, Schedule P3, line 6.

- 4
- 5

6

#### Q16. How did the Company calculate the projected 2024 energy sales revenue net of projected fuel costs per Section 6w(3)(B) of Act 341?

7 A16. Section 6w(3)(B) of Act 341 requires that the revenue, net of projected fuel costs, 8 from energy market sales, off-system energy sales, ancillary services sales, and 9 energy sales under unit-specific bilateral contracts be subtracted from the 10 Company's capacity costs before calculating its capacity charge. I performed the 11 calculation consistent with the method as directed by the Commission in Case No. 12 U-20836 using the forecasted assumptions from the Company's 2023 PSCR Plan, 13 Case No. U-21259. To calculate the energy sales revenue net of projected fuel 14 related costs, first the projected wholesale energy revenue from the Company's 15 generation resources (including power purchase agreements) was determined 16 (Exhibit A-26, Schedule P3, line 11). Next, the projected wholesale revenue 17 associated with ancillary services provided by the Company's generation resources 18 was determined (Exhibit A-26, Schedule P3, lines 14 and 15). Finally, all fuel and 19 fuel related expenses associated with the wholesale energy and ancillary services 20 were determined (Exhibit A-26, Schedule P3, lines 20 - 23) and subtracted from 21 the projected wholesale revenues (Exhibit A-26, Schedule P3, line 16) resulting in 22 the energy sales revenue net of projected fuel related costs (Exhibit A-26, Schedule 23 P3, line 25).

<sup>&</sup>lt;sup>1</sup> MISO annual resource adequacy auctions cover the Planning Year from June 1st – May 31st. The 2023/24 Planning Year auction covers January 1st - May 31st, 2024 and the 2024/25 Planning Year auction covers June 1st - December 31st, 2024.

1	Q17.	What is the projected revenue associated with wholesale energy sales from the
2		Company's generation resources in 2024?
3	A17.	The Company receives wholesale energy revenues from the MISO wholesale
4		energy market for the electricity produced by its generation assets. The wholesale
5		energy revenues forecasted for all Company assets (including PPAs) in the
6		Company's 2023 PSCR Plan (U-21259) was calculated to be \$2.259 billion shown
7		on Exhibit A-26, Schedule P3, line 11. This was done by summing the hourly
8		generation multiplied by the corresponding hourly market price.
9		
10	Q18.	Is the Company projecting any off-system energy sales or sales under unit
11		specific bilateral contracts in 2024?
12	A18.	No. These values are shown as zero on Exhibit A-26, Schedule P3, lines 12 and
13		13.
14		
15	Q19.	What is the projected ancillary services revenue from the Company's
16		generation resources in 2024?
17	A19.	The Company receives wholesale revenue for providing the following ancillary
18		services: regulation reserves, spinning reserves, supplemental, and short-term
19		reserves (all settled via MISO's energy and ancillary services market) and reactive
20		reserves (settled per Schedule 2 of the MISO tariff). The Company's 2023 PSCR
21		Plan projected that Company's generation resources would generate \$2.8 million
22		of wholesale revenue associate with regulation, spinning, and supplemental
23		reserves and \$8.9 million of revenue associated with Schedule 2 reactive reserves.
24		The projected wholesale ancillary services revenues from the Company's

	S. D. BURGDORF U-21297
	generation resources in 2024 are shown on Exhibit A-26, Schedule P3, lines 14 and 15.
Q20.	What is the total projected wholesale energy sales revenue including ancillary
A20.	The total projected wholesale energy sales revenue including ancillary services in 2022 is \$2.271 billion as shown on Exhibit A-26, Schedule P3, line 16.
Q21.	What is the projected fuel and fuel related cost required to generate the projected wholesale energy and ancillary services sales from the Company's
	generation resources in 2024?
A21.	The projected fuel and fuel related cost required to make the energy and ancillary services market sales is projected from the generation in the 2023 PSCR Plan and includes: fuel, emission allowance expenses, fuel chemical expenses, variable component of power purchase agreements, and the variable component of renewables (based on removing the fixed component of the MPSC-approved transfer prices from the overall transfer price). Total projected fuel and fuel related costs for the Company's generation fleet are \$1,204.5 million as shown on Exhibit A-26, Schedule P3, line 23.
Q22.	How did you address the MISO market administrative costs associated with
	Schedule 17?
	I removed the Schedule 17 costs from being included in the "fuel related" costs in

Line <u>No.</u>

in accordance with the recent Commission Order in case U-20836. However, I believe that these costs should be included in "fuel-related" costs because they are 

1		directly attributable to "injections" of energy into MISO and would not be incurred
2		if the generation sales did not occur. To give the "benefit" of the energy sales to
3		customers being charged the State Reliability Mechanism (SRM) without including
4		all the attributable costs to produce the energy is not fair to the Company's PSCR
5		customers who end up paying those extra costs, thus subsidizing customers on the
6		SRM Capacity Charge.
7		
8	Q23.	What was the Company's actual wholesale energy sales revenue net of fuel
9		related costs in 2021?
10	A23.	I calculated the Company's actual wholesale energy sales revenue net of fuel
11		related costs in 2021; this amount is \$772.1 million, which is shown on Exhibit A-
12		26, Schedule P4, line 12, column (c). That actual amount was \$328.8 million more
13		than the projected wholesale energy sales revenue net of fuel related costs
14		embedded in the Company's rate design in effect in 2021.
15		
16	Q24.	What is the Company's projected wholesale energy sales revenue net of
17		projected fuel costs per Section 6w(3)(B) of Act 341 for 2024 including the
18		reconciliation of 2021?
19	A24.	The total projected 2024 wholesale energy sales revenue of \$2.271 billion, net of
20		\$1.204 billion in fuel related costs equates to \$1.066 billion wholesale energy sales
21		revenue net of fuel related costs as shown on Exhibit A-26, Schedule P3, line 25.
22		The reconciliation of the net sales benefit difference for 2021 of \$328.8 million
23		(Exhibit A-26, Schedule P4, Line 12, column (d)) was added to the 2024 projection
24		resulting in an amount of \$1.395 billion (Exhibit A-26, Schedule P3, Line 27). This

Line <u>No.</u>		S. D. BURGDORF U-21297
1		amount was provided to Company Witness Maroun to develop his capacity related
2		cost of service.
3		
4	Q25.	Does this complete your direct testimony?
5	A25.	Yes, it does.

#### STATE OF MICHIGAN

#### BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)
DTE ELECTRIC COMPANY	)
for authority to increase its rates, amend	)
its rate schedules and rules governing the	)
distribution and supply of electric energy, and	)
for miscellaneous accounting authority.	)

Case No. U-21297

#### QUALIFICATIONS

#### AND

#### DIRECT TESTIMONY

OF

#### MICHAEL S. COOPER

### DTE ELECTRIC COMPANY QUALIFICATIONS AND DIRECT TESTIMONY OF MICHAEL S. COOPER

Line <u>No.</u>

1	Q1.	What is your name, business address and by whom are you employed?
2	A1.	My name is Michael S. Cooper (he/him/his). My business address is DTE Energy
3		Company, One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE
4		Energy Corporate Services, LLC (DTE LLC), a subsidiary of DTE Energy
5		Company (DTE Energy).
6		
7	Q2.	On whose behalf are you testifying?
8	A2.	I am testifying on behalf of DTE Electric Company (DTE Electric or Company).
9		
10	Q3.	What is your educational background?
11	A3.	I received a Bachelor of Business Administration Degree with a major in
12		accounting and finance from the University of Toledo in 1994. I received a Master
13		of Arts Degree in educational administration from Michigan State University in
14		1997.
15		
16	Q4.	What is your current position and work experience?
17	A4.	My current position is Director of Compensation, Benefits & Wellness. I joined
18		DTE LLC full time in 2008 and held positions with increasing responsibility in
19		Human Resources. In 2012, I became the Manager of Compensation and assumed
20		my current position in 2017. Prior to joining DTE LLC, I was employed by
21		Manpower as an on-site Staffing Program Manager and in other related positions
22		for Visteon Corporation. I was previously employed at Robert William James &
23		Associates as a recruiter with an emphasis in accounting and finance related
24		positions.

1	Q5.	What are your current responsibilities as Director of Compensation, Benefits			
2		& Wellness	??		
3	A5.	As Director of Compensation, Benefits & Wellness, I have overall responsibilit			
4		for the design, implementation, and administration of DTE Energy's compensation			
5		and employee benefits related policies and practices.			
6					
7	Q6.	Have you previously sponsored testimony before the Michigan Public Service			
8		Commission (MPSC or Commission)?			
9	A6.	Yes. I have sponsored testimony in the following cases:			
10		U-18255	2017 DTE Electric General Rate Case		
11		U-18999	2017 DTE Gas General Rate Case		
12		U-20162	2018 DTE Electric General Rate Case		
13		U-20561	2019 DTE Electric General Rate Case		
14		U-20642	2019 DTE Gas General Rate Case		
15		U-20836	2022 DTE Electric General Rate Case		
16		U-20940	2021 DTE Gas General Rate Case		

#### 1 **Purpose of Testimony**

2	Q7.	What is the purpose of your testimony?			
3	A7.	My testimony will present an overview of employee compensation practices and			
4		benefit expense for DTE Electric for the 2021 historical test period and the 12			
5		months ended November 30, 2024, projected test period. Specifically, I will:			
6		1. Provide support for the Company's projected pension costs, other post-			
7		employment benefits costs (OPEB), active employee health care costs and the			
8		costs of other employee benefits;			
9		2. Support the Company's labor cost escalation assumptions used in Company			
10		Witness Uzenski's development of the composite inflation factors for the			
11		projected test period;			
12		3. Provide an overview of the Company's compensation philosophy for non-			
13		represented employees and the role that the Company's incentive plans play in			
14		the overall reasonableness of its total compensation policies, including an			
15		analysis of salaries for non-represented positions as of December 31, 2021,			
16		relative to the market medians for comparable positions;			
17		4. Describe the components of the Company's short-term and long-term incentive			
18		compensation plans and support the inclusion of such cost in the Company's			
19		revenue requirement, exclusive of the costs related to DTE Energy's Top Five			
20		Executive Officers; and			
21		5. Demonstrate that the quantifiable customer benefits of the Company's			
22		incentive compensation plans exceed the corresponding expense, as required by			
23		the Commission's traditionally mandated cost/benefit analysis of incentive			
24		compensation expense.			
25					

Line <u>No.</u>

Line <u>No.</u>				U-21297
1		In summary,	my testimony	will support the reasonableness and validity of the
2		projected em	ployee benefits	s and compensation expense to be incurred by DTE
3		Electric for the	ne projected tes	t period.
4				
5	Q8.	Are you spor	nsoring any ex	hibits in this proceeding?
6	A8.	Yes. I am spo	onsoring in who	ble, or in part, the following exhibits:
7		<u>Exhibit</u>	Schedule	Description
8		A-13	C5.11	Projected Operation and Maintenance Expenses -
9				Employee Pensions and Benefits
10		A-13	C5.11.1	Willis Towers Watson Healthcare Trend Projection
11		A-13	C5.11.2	PwC 2022 Medical Cost Trend
12		A-13	C5.11.3	Constant Dollar Active Healthcare Adjustment
13		A-13	C5.12.1	Projected Operation and Maintenance Expenses -
14				Pension Costs- Qualified
15		A-13	C5.12.2	Projected Operation and Maintenance Expenses -
16				Other Post-Employment Benefits (OPEB)
17		A-21	K1	Employee Compensation Market Analysis:
18				December 31, 2021
19		A-21	K2	2022 Annual Incentive Plan and Rewarding
20				Employees Plan Metrics: DTE Electric Company
21		A-21	K3	2022 Annual Incentive Plan and Rewarding
22				Employees Plan Metrics: Nuclear Generation
23		A-21	K4	2022 Annual Incentive Plan and Rewarding
24				Employees Plan Metrics: DTE Energy Corporate
25				Services LLC

Line <u>No.</u>				<b>M. S. COOPER</b> U-21297	
1		A-21	K5	2022 Long-Term Incentive Plan Performance Shares	
2				Metrics	
3		A-21	K6	2022 Incentive Plans Cost/Benefit Analysis	
4					
5	Q9.	Were these exhibits prepared by you or under your direction?			
6	A9.	Yes, they were. Portions of Exhibit A-13, Schedule C5.11 are sponsored by			
7		Witness Uzenski.			
8					
9	EMP	LOYEE PENSION COSTS			
10	Q10.	What are pension costs?			
11	A10.	Pension costs are those costs related to retirement benefits to the employees of DTE			
12		Electric that are eligible to participate in the Company's defined benefit pension			
13		plans. The Company's defined benefit pension costs are recognized under			
14		Financial Accounting Standard Board's Accounting Standard Codification (ASC)			
15		Section 715-30 (ASC 715-30), formerly known as Statement of Financial			
16		Accounting Standard 87.			
17					
18	Q11.	What are the components of pension costs?			
19	A11.	Pension costs are measured at the beginning of each fiscal year, under ASC 715-			
20		30, and include the following four pension cost components:			
21					
22		Service Cost	<u>s:</u> Service Co	osts represent the pension benefits earned by active	
23		employees, or	n a present va	lue basis, during the current period. Service Costs are	
24		measured bas	ed on the expe	ected benefits to be paid based on actuarial assumptions	

1

2

3

including current and projected salaries, expected employee turnover, and life expectancy.

4 Interest Costs: Interest Costs are the increase in the Projected Benefit Obligation 5 (PBO) due to the passage of time during the current period. The PBO is the 6 actuarial present value of benefits attributable to the pension benefit formula and 7 service accrued to date discounted back to current dollars at a discount rate selected 8 at the prior year-end. A discount rate of 2.91% was used in determining the PBO 9 as of December 31, 2021. Measuring the PBO as a present value at the beginning 10 of each fiscal year requires the accrual of an interest cost for the current period at a 11 rate equal to the prior year's discount rate. The discount rate used in measuring 12 Interest Costs, as well as Service Costs for the 2021 historical test period, was 13 2.57%, based on the interest rate environment at the end of 2020, and projected 14 benefit payments from the pension plan matched against a yield curve of corporate 15 bond rates, rated A or higher, provided by Aon, the Company's independent 16 actuarial firm. This was then reviewed by PriceWaterhouseCoopers (PwC), the 17 Company's independent accounting firm in connection with its audit of the 18 Company's financial statements as filed with the Securities and Exchange 19 Commission (SEC). The 2.91% discount rate used for determining Interest Costs 20 and Service Costs for the projected test year is based on the discount rate as of 21 December 31, 2021, which reflects the traditional assumption that high-quality 22 corporate bond yields at the end of 2021 will remain essentially unchanged from 23 the rates prevailing in the historical test year.

1 Expected Return on Assets: The Expected Return on Assets is an estimate of the 2 expected investment return, during the current period, on the Market Related Value 3 of the assets invested in the pension trust at the beginning of the year adjusted for 4 any expected funding activity and projected benefit payments for the year. While 5 actual year-to-year investment returns can vary significantly, the expected annual 6 rate of return is determined based on long-term financial market expectations to 7 avoid large swings in pension costs based on short-term investment performance. 8 DTE Electric's expected annual return was 7.00% for the 2021 historical test year, 9 as developed by NEPC LLC, the Company's independent investment consulting 10 firm and reviewed by PwC in connection with its audit of the Company's financial 11 statements as filed with the SEC. The expected rate of return used in 2022 is 6.80% 12 and is reduced to 6.60% in 2023, and 6.20% in 2024. The reductions in the expected 13 rate of return reflect a decrease in the long-term capital market assumptions and a projected increased asset allocation to fixed income assets, with lower expected 14 15 returns, due to the projected increase in pension trusts funding relative to the 16 pension liabilities. These projections are based on market conditions and pension 17 funding status as of late 2021.

18

Line

No.

Amortizations: In addition to current period costs described above, pension costs also include the effect of the delayed recognition of prior period costs. This includes Unrecognized Gains and Losses and Prior Service Costs. Unrecognized Gains and Losses are changes in the amount of either the PBO or the plan's assets resulting from experience different from that assumed in actuarial assumptions. Most notably, since discount rates and return on assets assumptions are based on either point in time measurements or long-term estimates of expected returns,
1		differences arise whenever a change is made in the discount rates or when the actual
2		asset returns differ from long-term expectations. These gains and losses are
3		deferred and the amount of the unrecognized balance in excess of a corridor equal
4		to 10% of the greater of the PBO or the Market Related Value of assets is amortized
5		based on a period equal to the average remaining service life of employees covered
6		by the plans. Prior Service Costs arise from pension plan amendments that affect
7		future benefits. When a plan provision is changed that will affect future benefit
8		payments for existing employees or retirees, the resulting change in the PBO
9		liability is amortized over the average remaining years of service life of the active
10		employees.
11		
12	Q12.	What is the level of pension funding reflected in the projected pension costs?
13	A12.	Based on the pension funding status on December 31, 2021, the Company is not
14		expected to fund pension plans in 2022, 2023, or 2024. While there is no planned
15		funding of the pension trusts, \$50 million of pension assets related to the Gas Non-
16		Union plan are expected to be transferred to DTE Electric's pension trust assets in
17		both 2022 and 2023, for a total of \$100 million. The reasons for these transfers are
18		explained by Witness Uzenski.
19		
20	Q13.	How are pension costs expected to change between the historical test year and
21		the projected year?

A13. As summarized on Exhibit A-13, Schedule C5.12.1, the Company's pension costs
are projected to decrease from \$95.826 million during the historical test year, which
includes the one-time cost of \$3.500 million that was related to a settlement in 2021,
to negative \$7.102 million for the projected test year. This reduction in pension

	costs is almost completely due to the elimination of the one-time cost in 2021 and a
	projected reduction in the amortization of Unrecognized Gains and Losses, which
	reflects the investment gains in 2020 and 2021, and the gain from the reduction the
	pension liabilities resulting from the increase in the discount rate as of December
	31, 2021.
	The total projected pension cost of negative \$7.102 million is adjusted for the impact
	of costs transferred and capitalized, as described by Company witness Uzenski,
	which results in negative pension expense of \$3.274 million for the projected test
	year.
Q14.	Is the negative pension expense included in the Company's proposed revenue
	requirement?
A14.	No. Witness Uzenski sponsors the Company's proposal to continue to defer the
	projected negative pension expense to the accumulated regulatory liability as
	authorized by the Commission in its Order in Case No. U-20836. Thus, the
	projected negative pension expense is not reflected in the Company's proposed
	revenue requirement and the negative pension expense is eliminated on line 20 of
	Exhibit A-13, Schedule C5.12.1.
Q15.	Will the Company's actual pension cost during the projected test year be
	impacted by changes in discount rates and differences in the actual return on
	assets relative to the expected return?
A15.	Yes. The Company's projected Pension costs are based on discount rates as of
	December 31, 2021, and the Company's expected rate of return on assets is based
	<b>Q14.</b> A14. <b>Q15.</b>

1 on long-term investment performance expectations based on the funded status as of 2 December 31, 2021. However, changes in the interest rate environment and 3 substantial declines in virtually all investment classes during 2022 suggest that the 4 Company's actual pension costs will be much higher than projected. However, this 5 increase in pension costs will also be deferred. 6 7 **OTHER POST-EMPLOYMENT BENEFITS** 8 Q16. What are OPEB Costs? 9 A16. OPEB costs relate to the provision of retiree medical, dental, prescription drug and 10 life insurance benefits. OPEB is a cost recognized under U.S. GAAP Accounting 11 Standard Codification (ASC) section 715-60. Similar to ASC 715-30, OPEB costs 12 are determined under ASC 715-60 at the beginning of each fiscal year. 13 14 What are the cost components of OPEB? 017. 15 A17. OPEB has the same basic cost components as pension costs. They are: 16 17 Service Costs: Service Costs are the portion of the expected post-retirement benefit 18 obligation, on a present value basis, attributable to employee participation service 19 during the current period. Service Costs reflect actuarial assumptions of employee 20 turnover, age at retirement, and expected longevity. Service Costs also depends on 21 the estimated costs of providing these benefits after the employee's retirement and, 22 therefore, is impacted by both current medical cost levels and expected medical 23 cost inflation.

24

Line
No.

1	Interest Costs: Interest Costs are the costs arising from the current period interest
2	on the discounted Accumulated Post-Retirement Benefit Obligation (APBO). The
3	APBO was discounted to today's dollars based on a discount rate of 2.91% as of
4	December 31, 2021, which was also used to determine Interest Costs on the APBO
5	during the projected test year. The discount rate used in measuring Interest Costs
6	as well as Service Costs for the historical test period was 2.58%, based on the
7	interest rate environment at the end of 2020, as determined in a similar manner to
8	the measurement of the Company's pension costs, as described above.
9	
10	Expected Return on Assets: The Expected Return on Assets is an offset to the costs
11	of OPEB, based on the expected long-term return on assets invested. The expected
12	annual rate of return was 6.70% during the historical test year and is assumed to be
13	6.40% in both 2022 and 2023, and 6.30% in 2024. These reductions reflect a
14	decrease in the expected long-term capital market returns and an expected increase
15	in asset allocation to fixed income investments, based on market conditions and
16	funding status at the end of 2021.
17	
18	Amortizations: This cost component includes the amortizations related to deferred
19	Gains and Losses as well as Prior Service Costs. Accumulated gains and losses,
20	outside the 10% corridor, as described for pension costs, are amortized over the
21	current estimated remaining service life of active participants. Prior Service Costs

- are amortized over the estimated remaining service life of active participants, at the
  time of the last plan change, to the age at which these employees are fully eligible
  for the benefits.
- 25

1	Q18.	How are these OPEB costs expected to change between the historical test year
2		and the projected test year?
3	A18.	As reflected on Exhibit A-13, Schedule C5.12.2, the Company's OPEB costs are
4		projected to decrease from negative \$31.445 million in the historical test year to
5		negative \$36.435 million during the projected test year, which represents a decrease
6		in OPEB costs of \$4.990 million. The decrease in OPEB costs is primarily due to
7		the projected reduction in the Amortization of Net (Gain)/Loss as result of
8		investment gains in 2020 and 2021 partially offset by a projected increase in the
9		Amortization of Prior Service Costs due to a reduction in unamortized balance.
10		
11		The total projected OPEB cost of negative \$36.435 million is adjusted for the
12		impact of costs transferred and capitalized, as described by Company witness
13		Uzenski, which results in negative OPEB expense of \$21.424 million for the
14		projected test year.
15		
16	Q19.	Is the negative OPEB expense included in the Company's proposed revenue
17		requirement?
18	A19.	No. Witness Uzenski sponsors the Company's proposal to continue to defer to the
19		projected negative OPEB expense to the accumulated regulatory liability. Thus,
20		the projected OPEB expense is not reflected in the Company's proposed revenue
21		requirement and the negative OPEB expense is eliminated on line 18 of Exhibit A-
22		13, Schedule C5.12.2.
23		
24	Q20.	Has DTE Electric previously externally funded its OPEB costs?

Line	
Ma	

N	o	١.

1	A20.	Yes. DTE Electric has generally funded the OPEB costs included in the Company's
2		revenue requirement adopted by the Commission in previous orders through a
3		Voluntary Employees' Beneficiary Association (VEBA) trust and an Internal
4		Revenue Code Section 401(h) trust.
5		
6	Q21.	Will the Company externally fund its OPEB liability in the future?
7	A21.	No. Since the Commission approved the Company's proposal in Case No. U-20836
8		to continue the deferral of the projected negative OPEB expense, initially approved
9		by the Commission in Case No. U-17767, the Company's current and projected
10		revenue requirements do not include any OPEB expense and thus there is no
11		obligation for the Company to externally fund its OPEB liability.
12		
12 13	<u>NEW</u>	HIRE VEBA AND EMPLOYEE SAVINGS PLAN COSTS
12 13 14	<u>NEW</u> Q22.	HIRE VEBA AND EMPLOYEE SAVINGS PLAN COSTS What is the basis for the projected cost increase in the New Hire Retiree
12 13 14 15	<u>NEW</u> Q22.	HIRE VEBA AND EMPLOYEE SAVINGS PLAN COSTS What is the basis for the projected cost increase in the New Hire Retiree VEBA?
12 13 14 15 16	<u>NEW</u> Q22. A22.	HIRE VEBA AND EMPLOYEE SAVINGS PLAN COSTS What is the basis for the projected cost increase in the New Hire Retiree VEBA? The New Hire Retiree VEBA costs on Exhibit A-13, Schedule C5.11, line 4 reflect
12 13 14 15 16 17	<u>NEW</u> Q22. A22.	HIRE VEBA AND EMPLOYEE SAVINGS PLAN COSTS What is the basis for the projected cost increase in the New Hire Retiree VEBA? The New Hire Retiree VEBA costs on Exhibit A-13, Schedule C5.11, line 4 reflect the costs of the DTE Supplemental Retiree Benefits Plan that is offered in lieu of
12 13 14 15 16 17 18	<u>NEW</u> Q22. A22.	HIRE VEBA AND EMPLOYEE SAVINGS PLAN COSTS What is the basis for the projected cost increase in the New Hire Retiree VEBA? The New Hire Retiree VEBA costs on Exhibit A-13, Schedule C5.11, line 4 reflect the costs of the DTE Supplemental Retiree Benefits Plan that is offered in lieu of the traditional retiree healthcare plan for eligible employees. The New Hire Retiree
12 13 14 15 16 17 18 19	<u>NEW</u> Q22. A22.	HIRE VEBA AND EMPLOYEE SAVINGS PLAN COSTS What is the basis for the projected cost increase in the New Hire Retiree VEBA? The New Hire Retiree VEBA costs on Exhibit A-13, Schedule C5.11, line 4 reflect the costs of the DTE Supplemental Retiree Benefits Plan that is offered in lieu of the traditional retiree healthcare plan for eligible employees. The New Hire Retiree VEBA expense is projected to increase from \$7.272 million in the historic test year
12 13 14 15 16 17 18 19 20	<u>NEW</u> Q22. A22.	HIRE VEBA AND EMPLOYEE SAVINGS PLAN COSTS What is the basis for the projected cost increase in the New Hire Retiree VEBA? The New Hire Retiree VEBA costs on Exhibit A-13, Schedule C5.11, line 4 reflect the costs of the DTE Supplemental Retiree Benefits Plan that is offered in lieu of the traditional retiree healthcare plan for eligible employees. The New Hire Retiree VEBA expense is projected to increase from \$7.272 million in the historic test year to \$13.967 million in the projected test year, which is based on annual escalations
12 13 14 15 16 17 18 19 20 21	<u>NEW</u> Q22. A22.	HIRE VEBA AND EMPLOYEE SAVINGS PLAN COSTS What is the basis for the projected cost increase in the New Hire Retiree VEBA? The New Hire Retiree VEBA costs on Exhibit A-13, Schedule C5.11, line 4 reflect the costs of the DTE Supplemental Retiree Benefits Plan that is offered in lieu of the traditional retiree healthcare plan for eligible employees. The New Hire Retiree VEBA expense is projected to increase from \$7.272 million in the historic test year to \$13.967 million in the projected test year, which is based on annual escalations of 25%, based on the Company's recent experience. This increase reflects the
12 13 14 15 16 17 18 19 20 21 22	<u>NEW</u> Q22. A22.	HIRE VEBA AND EMPLOYEE SAVINGS PLAN COSTS What is the basis for the projected cost increase in the New Hire Retiree VEBA? The New Hire Retiree VEBA costs on Exhibit A-13, Schedule C5.11, line 4 reflect the costs of the DTE Supplemental Retiree Benefits Plan that is offered in lieu of the traditional retiree healthcare plan for eligible employees. The New Hire Retiree VEBA expense is projected to increase from \$7.272 million in the historic test year to \$13.967 million in the projected test year, which is based on annual escalations of 25%, based on the Company's recent experience. This increase reflects the growth in the number of plan participants due to new hires. Since the New Hire
12 13 14 15 16 17 18 19 20 21 22 23	<u>NEW</u> Q22. A22.	HIRE VEBA AND EMPLOYEE SAVINGS PLAN COSTS What is the basis for the projected cost increase in the New Hire Retiree VEBA? The New Hire Retiree VEBA costs on Exhibit A-13, Schedule C5.11, line 4 reflect the costs of the DTE Supplemental Retiree Benefits Plan that is offered in lieu of the traditional retiree healthcare plan for eligible employees. The New Hire Retiree VEBA expense is projected to increase from \$7.272 million in the historic test year to \$13.967 million in the projected test year, which is based on annual escalations of 25%, based on the Company's recent experience. This increase reflects the growth in the number of plan participants due to new hires. Since the New Hire Retiree VEBA is offered in lieu of the Company's traditional retiree healthcare

25 costs.

<b>.</b> .		M. S. COOPER
Line <u>No.</u>		0-21297
1		
2	Q23.	What is the basis for the projected Employee Savings Plan costs?
3	A23.	The Company's Employee Savings Plan allows eligible employees the opportunity
4		to put aside a certain percentage of their annual earnings that the Company matches
5		up to 6% of annual salaries and wages for non-represented employees and for most
6		represented groups. In addition, employees hired after the defined benefit pension
7		plan was closed to most new hires generally receive an additional employer
8		contribution of 4.0% of annual salaries and wages, although certain represented
9		employee groups instead receive a match of 8.0%. The Employee Savings Plan
10		costs reflected on Exhibit A-13, Schedule C5.11, line 5, are projected to increase
11		from \$29.079 million in the historic test year to \$36.405 million in the projected
12		test year, which reflects an 8.0% annual increase in the Company's Employee
13		Savings Plan costs based on recent Company experience.
14		
15	ACTI	VE EMPLOYEE BENEFIT PROGRAMS
16	Q24.	What other benefit programs are offered to active employees?

17 A24. The Company offers a competitive active employee benefits package for the 18 attraction and retention of a skilled workforce. The components of these benefits 19 are summarized on Exhibit A-13, Schedule C5.11. The largest component in this 20 category is the cost of Active Healthcare, which consists of medical, dental, and 21 vision benefits for active employees, and are projected to increase from \$51.269 22 million in the historic test year to \$56.961 million in the projected test year as 23 reflected on Exhibit A-13, Schedule C5.11, line 11. This increase reflects the 24 normalization of the 2021 Active Healthcare costs to reflect an historical average 25 of constant dollar costs and annual escalations for the adjusted medical plan trend

10.		
1		of 6.0% in 2022, 5.50% in 2023, and 5.0% in 2024, as more fully described below.
2		Life Insurance costs, as reflected on line 12, are projected to remain essentially flat
3		in the projected test year. Benefit Plan Administration Fees, as shown on line 13
4		are projected to increase from \$6.442 million in 2021 to \$7.422 million for the
5		projected test year due to the overall rate of inflation as measured by the Consumer
6		Price Index.
7		
8	Q25.	What is the Rate Case Adjustment to 2021 Active Healthcare costs as reflected
9		on Exhibit A-13, Schedule C5.11?
10	A25.	The year-to-year volatility of actual Active Healthcare costs makes the use of any
11		one historical period's expense an unreliable starting point in the determination of
12		projected Active Healthcare costs. Accordingly, the adjustment of a \$2.566 million
13		reduction, as reflected on Exhibit A-13, Schedule C5.11, page 2 on line 11 of
14		column (c), represents a normalization of the Company's actual 2021 Active
15		Healthcare costs that is designed to eliminate the volatility of the Company's Active
16		Healthcare costs through the quantification of the Company's historical Active
17		Healthcare costs per employee as adjusted for national historical healthcare cost
18		trends. This results in an average of the Company's actual Active Healthcare costs
19		per employee stated on a basis that adjusts for the impact of historical healthcare
20		cost inflation.
21		
22	Q26.	What is the basis for your conclusion that year-to-year Active Healthcare costs
23		are volatile?
24	A26.	Active Healthcare costs are volatile because they are dependent upon multiple

25 factors. For example, the Company is self-insured for about 80% of its total Active

1		
1		Healthcare costs. Self-insurance results in the level of Active Healthcare costs
2		incurred by the Company being highly impacted by the mix and severity of medical
3		treatments administered to employees and their eligible dependents. The
4		Company's Active Healthcare costs are also impacted by the number of employees
5		and dependents eligible for coverage, which can vary from year to year due to both
6		changes in the number of employees and the number of employees that opt out of
7		the Company's medical plans.
8		
9	027	Have you quantified the degree of volatility in the Company's Active
10	Q21.	Haaltheare Costs?
10		nearthcare Costs:
11	A27.	Yes. The actual annual percentage change in the Company's Active Healthcare
12		costs for the years 2013 through 2021, as adjusted for a one-time credit in 2018, is
13		reflected in Table 1 below.
13 14		reflected in Table 1 below. Table 1
13 14 15		reflected in Table 1 below. Table 1 Active Healthcare Costs
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> </ol>		reflected in Table 1 below. Table 1 Active Healthcare Costs Annual Percent Change 2013 - 2021
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> </ol>		reflected in Table 1 below. Table 1 Active Healthcare Costs Annual Percent Change 2013 - 2021 30.0%
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> </ol>		reflected in Table 1 below.          Table 1         Active Healthcare Costs         Annual Percent Change         2013 - 2021       30.0%         25.0%       25.4%
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> </ol>		reflected in Table 1 below. Table 1          Active Healthcare Costs         Annual Percent Change         2013 - 2021         30.0%         25.0%       25.4%         20.0%
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> </ol>		reflected in Table 1 below. Table 1          Active Healthcare Costs         Annual Percent Change         2013 - 2021         30.0%         25.0%         20.0%         15.0%
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> </ol>		reflected in Table 1 below. Table 1 Active Healthcare Costs Annual Percent Change 2013 - 2021 30.0% 25.0% 25.0% 25.4% 15.0% 10.0% 8.7% 6.4%
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> </ol>		reflected in Table 1 below. Table 1 Active Healthcare Costs Annual Percent Change 2013 - 2021 30.0% 25.0% 25.0% 15.0% 10.0% 6.4% 5.0% (0.1%)
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>22</li> <li>22</li> </ol>		reflected in Table 1 below. Table 1 Active Healthcare Costs Annual Percent Change 2013 - 2021 30.0% 25.0% 25.0% 15.0% 10.0% 5.0% (0.1%) 0.0% 25.4% 3.3% 10.0% 25.4% 2011 25.4% 25.4% 25.4% 2012 25.4% 25.4% 25.4% 2016 25.4% 25.4% 25.4% 2017 25.4% 25.4% 2017 25.4% 25.4% 25.4% 20.0% 25.4% 20.0% 2
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>23</li> <li>24</li> </ol>		reflected in Table 1 below. Table 1 Active Healthcare Costs Annual Percent Change 2013 - 2021 30.0% 25.0% 25.0% 25.0% 25.4% 20.0% 15.0% 10.0% 6.4% 5.0% 0.0% 2014 2015 2016 2017 2018 2019 2020 2021 (5.0%) (1.5%) (1.5%)
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>23</li> <li>24</li> </ol>		reflected in Table 1 below. Table 1 Active Healthcare Costs Annual Percent Change 2013 - 2021 30.0% 25.0% 25.0% 25.0% 25.0% 25.0% 25.4% 20.0% 15.0% 10.0% 5.0% 0.0% 2013 - 2021 3.3% 20.0% 15.0% 10.0% 2014 2015 2016 2017 2018 2019 2020 2021 (5.0%) (1.6%) (1.5%) (4.6%)

Line

The chart in Table 1 shows that the Company's actual Active Healthcare costs have
changed relative to the prior year by as much as a 25.4% increase in 2021 to a 4.6%
decrease in 2020 demonstrating that Active Healthcare costs can vary significantly
from year-to-year. **Q28.** What other conclusions do you draw from the data reflected in Table 1?
The high variability of the percent charge in the Company's actual Active

7 A28. The high variability of the percent change in the Company's actual Active 8 Healthcare costs highlights the inherent flaw in using historical annual changes in 9 the Company's Active Healthcare costs as the basis for projecting future increases. 10 Specifically, while the average annual percentage increase in the Company's actual 11 Active Healthcare costs for the year 2013 through 2021 is 3.7%, the Standard 12 Deviation of that average is 9.3%. This means that for about 68% of future years, 13 the Company's annual change in Active Healthcare costs could range from a 14 decrease of 5.6% to an increase of 12.9%.

15

# Q29. What is the significance of this high degree of variability in the percentage change in the Company's actual Active Healthcare costs?

18 A29. Because increases in the Company's Active Healthcare costs can be impacted by 19 variations in usage, the effect of benefit plan design, and changes in pricing, they 20 are unreliable measures to determine projected increases in Active Healthcare costs. 21 Moreover, the population of the Company's employees is simply too small to infer 22 that the experience over a few years will reflect the long-term trends in the costs of 23 Active Healthcare. For example, in 2020 DTE Electric's medical claims related to 24 outpatient specialty drugs decreased by over 25% compared to 2019 while in 2021 25 claims for the same category increased by almost 90%. Because the Company had

		M. S. COOPER
Line <u>No.</u>		U-21297
1		less than 4,000 employees covered by the Company's Self-Insured medical plans
2		in 2021, it only takes a few extraordinary claims to have a dramatic impact on the
3		Company's actual Active Healthcare costs.
4		
5	Q30.	Is there a method of normalizing the Company's historical Active Healthcare
6		costs to determine a more reliable starting point in determining Active
7		Healthcare costs for the projected test year?
8	A30.	Yes. The variability in the Company's actual Active Healthcare costs can be
9		normalized using constant dollar Active Healthcare costs on a per employee basis.
10		This allows for the normalization of the inherent volatility in historical Active
11		Healthcare costs through the elimination of the impact of healthcare price level
12		changes and changes in the level of employees.
13		
14	Q31.	How did you determine a constant dollar average of the Company's Active
15		Healthcare costs on a per employee basis?
16	A31.	Exhibit A-13, Schedule C5.11.3 reflects the Company's actual Medical, Dental,
17		and Vision components of the actual Active Healthcare costs for the years 2017
18		through 2021, before the impact of the costs capitalized and transferred. These
19		costs are divided by the simple average of employees at the beginning and end of
20		each year to develop the Active Healthcare costs per employee. The Active
21		Healthcare costs per employee for each year is then adjusted for the actual percent
22		increase in medical trends, as reported by PwC on page 3 of Exhibit A-13, Schedule
23		C5.11.2. <sup>1</sup> Adjusting the Company's actual Active Healthcare costs for the overall
24		increases in medical costs experienced by a broad universe of employers and

<sup>&</sup>lt;sup>1</sup> The Life Insurance and Benefit Plan Administration Fees have been excluded from this analysis because these items are subject to separate escalation factors.

1		insurance providers, as reflected in the PwC study, enables the separation of the
2		Company's year-to-year variability that is driven by changes in utilization by
3		employees and their dependents from changes to overall healthcare cost trends.
4		
5		The adjustment of each year's Active Healthcare costs per employee produces a
6		five-year average cost per employee on a constant dollar basis of \$11,860. By
7		multiplying this amount by the 2021 average number of Electric and Electric-
8		related LLC employees of 6,751, a total constant dollar Active Healthcare cost of
9		\$80.065 million is generated. This represents a \$4.218 million decrease relative to
10		the Company's incurred Active Healthcare costs in 2021. This amount is adjusted
11		for the 60.8% of Active Healthcare costs charged to expense and results in a
12		constant dollar normalization adjustment of negative \$2.566 million, as reflected
13		on Exhibit A-13, Schedule C5.11.3, column (m), line 16.
14		
15	Q32.	Does the fact that the constant dollar adjustment for DTE Electric in 2021 is a
16		reduction to actual costs provide any insights on the reasonableness of the
17		constant dollar normalization adjustment?
18	A32.	Yes. DTE Electric experienced a significant reduction in its Active Healthcare
19		costs in 2020 because of the postponement of the use of medical services during
20		the COVID-19 pandemic that resulted in a significant increase in medical services
21		used in 2021, as the availability of medical care was restored. This resulted in 2021
22		Active Healthcare costs being higher than normal as reflected in Table 1 above.
23		The negative constant dollar adjustment normalizes the 2021 Active Healthcare
24		costs to moderate the increase in Active Healthcare costs by reflecting a level of
25		Active Healthcare costs that doesn't rely exclusively on a single year's experience.

Line		<b>M. S. COOPER</b> U-21297
<u>No.</u> 1		This demonstrates that the constant dollar adjustment is a reasonable method of
1		
2		addressing the volatility in actual Active Healthcare costs.
3		
4	Q33.	Has the Commission previously addressed the propriety of a constant dollar
5		Active Healthcare adjustment?
6	A33.	Yes. In its Order in Case No. U-20940 the Commission declined to adopt the
7		constant dollar Active Healthcare cost adjustment based on its position that "a
8		multi-year average adequately captures the volatility of the expense" (Case No. U-
9		20940, Order issued December 9, 2021, p. 157).
10		
11	Q34.	Do you agree with the Commission's conclusion in Case No. U-20940?
12	A34.	No. Although the Commission acknowledged that Active Healthcare costs are
13		volatile, it used one year's actual Active Healthcare costs as the starting point for
14		projecting future Active Healthcare costs (i.e., actual 2019 costs x multi-year
15		average percentage of 3% x 3 years). The Commission's adoption of a multi-year
16		average of the historical annual percentage increases in the Company's Active
17		Healthcare costs in determining the escalation of historical test period Active
18		Healthcare costs for the projected test period did not address whether the historical
19		test period costs were a representative starting point to which the escalations should
20		be applied.
21		
22	Q35.	Does a multi-year average of historical increases in Active Healthcare costs
23		fully recognize the impact of volatility?
24	A35.	No. Averages of historical increases in the Company's actual Active Healthcare
25		costs only measures the annual changes in those costs, which is distinguishable



Active Healthcare costs in determining the starting point for escalation. Specifically, due to the spike in Active Healthcare costs in 2021, the data would suggest that the actual Active Healthcare costs for 2021 would be unrepresentative as a basis for future predictions. Similarly, the decline in Active Healthcare costs in 2020 makes the Active Healthcare costs incurred in 2020 an unreliable basis for projecting future costs. While the volatility in Active Healthcare costs in 2020 and 2021 was exacerbated by the impact of the COVID-19 pandemic and the

		M. S. COOPER
Line <u>No.</u>		U-21297
1		postponement of medical services from 2020 into subsequent years, the volatility
2		is evident in the prior years as well.
3		
4	Q36.	How has the Commission traditionally addressed cost elements that are
5		subject to volatility?
6	A36.	The Commission has routinely adopted prior year's average of the ratio of
7		uncollectibles to revenues to project future uncollectibles expense. The difference
8		is that, for uncollectibles the pricing is separated from the level of activity because
9		the ratios of uncollectibles are determined first, and then the ratio is priced by
10		applying the percentage of historical uncollectibles to projected revenue.
11		
12		In contrast, for Active Healthcare costs there is no available segregation of the
13		impact of changes in the level and mix of usage and pricing. Because the price of
14		healthcare services generally increases each year, it would be unreasonable to
15		predict future Active Healthcare costs based on an average of the historical Active
16		Healthcare costs. As a result, the only accurate means of producing a starting point
17		for Active Healthcare that is normalized for changes in utilization is to develop an
18		historical average that neutralizes the change in price levels. This is what the
19		Constant Dollar normalization adjustment achieves.
20		
21	Q37.	Are there any useful analogies to the Company's constant dollar Active
22		Healthcare adjustment?
23	A37.	Yes. From a broad perspective, the constant dollar Active Healthcare adjustment
24		should be regarded as means to neutralize the inherent volatility in the Company's
25		actual Active Healthcare costs by restating the historical costs in current dollars,

Line No.

NO

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3

4

much as "nominal" price levels are routinely adjusted for the effects of inflation to develop inflation adjusted "real" prices. This allows for a meaningful comparison of costs amongst years without the distortion of changes in price levels.

5 More specifically, for Emergent Replacement Expenditures in Distribution 6 Operations, the Company has traditionally adjusted its historical Emergent 7 Replacement Expenditures for inflation to develop a base spending level used in developing projected costs. 8 This approach was explicitly adopted by the 9 Commission in a Company's recent rate case where the Commission concluded 10 "Adding inflation to the historic five-year historical actual spend is appropriate for 11 calculating the starting point for normalized expenditures." (Case No. U-20561, 12 Order issued May 8, 2020, p. 86). The continued use of a five-year inflation 13 adjusted average of Emergent Replacement Expenditures was adopted by the 14 Commission in the Company's most recent rate case (Case No. U-20836, Order 15 issued November 11, 2022, p. 63). The constant dollar Active Healthcare 16 adjustment applies the same logic used in the development of normalized historical 17 Emergent Replacement Costs in recognition of the volatility among years of those 18 costs, and accordingly, the Commission should adopt the same methodology for 19 normalizing Active Healthcare costs.

20

# Q38. How is this constant dollar normalization adjustment reflected on Exhibit A13, Schedule C5.11?

A38. The total constant dollar normalization adjustment of \$2.566 million is allocated to
 the Active Healthcare cost components of Medical Expense, Dental Expense and

Line		M. S. COOPER U-21297
<u>No.</u>		
1		Vision Expense based on the proportion of the expenses for each of these categories
2		in 2021, as shown on Exhibit A-13 C5.11.3, column (m), lines 18 through 20.
3		
4	Q39.	What is the basis for your future trend factor in active healthcare costs used
5		for the projected periods in this proceeding?
6	A39.	The annual unadjusted medical plan trend factors of 7.50% for 2022, 2023 and
7		2024, are based on projections for healthcare trends provided by the healthcare
8		experts at Willis Towers Watson (WTW), as reflected in Exhibit A-13, Schedule
9		C5.11.1. These unadjusted trend factors are reduced by 1.50% in 2022, 2.00% in
10		2023, and 2.50% in 2024 to reflect the expected savings to be realized by the
11		Company's Wellness program. Accordingly, the active healthcare expense
12		projections are based on the Company's 2021 normalized expense as escalated by
13		the adjusted trend factors of 6.00% in 2022, 5.50% in 2023, and 5.00% in 2024.
14		
15	Q40.	How were these trend factors determined?
16	A40.	WTW's first step is to develop the Allowed Trend, which is based on its internal
17		guidance and represents a consensus expectation for medical and prescription drug
18		costs. WTW developed the Allowed Trend based on its internal book of business
19		and national surveys, as well as data from United States government offices and
20		agencies, and various third-party sources, as described on page four of Exhibit A-
21		13, Schedule C5.9.1. The Allowed Trend is adjusted for the Company's average
22		fixed plan design leveraging to develop the future Medical Plan Trend, which is the
23		basis of the Company's projected active healthcare costs.
24		

# Q41. Do any collaborating sources support the reasonableness of WTW's projections?

A41. Yes. A study released in 2021 by PwC's Health Research Institute as reflected in
Exhibit A-13, Schedule C5.11.2, projects that medical costs will increase by 7.0%
in 2021 and 6.5% in 2022. As described in the PwC study, these year over year
changes are derived with the impact of the COVID-19 pandemic excluded from the
prior year's numbers.

8

#### 9 Q42. What are Other Employee Benefits Costs?

10 A42. The costs of the Company's Other Employee Benefits are reflected on Exhibit A-11 13, Schedule C5.11. These costs include a variety of other benefits, including 12 Accrued Vacation, Supplemental Severance Plan costs, Wellness Plan, Long-Term 13 Disability, costs associated with the Affordable Care Act (ACA), Supplemental 14 Savings Plan (SSP), Deferred Compensation, General Benefits, and Retirement 15 Administration Fees. In total, these costs are projected to increase from \$8.820 16 million in the historic test year to \$11.092 million in the projected test year, as 17 shown on line 27. Also included in Other Employee Benefits Costs is the 18 amortization of the medical refund liability, as approved by the Commission in its 19 Order in Case No. U-20162 that will be fully amortized by April 2022 and O&M 20 Project Reimbursement Fees, which is sponsored by Witness Uzenski.

21

# Q43. What is the basis for your projection of the Company's Accrued Vacation expense?

A43. Accrued Vacation expense can vary from year to year based on the timing of the
 vacation earned and usage of vacation time by employees, as well as forfeitures.

1		This volatility in annual accrued vacation expense has been traditionally addressed
2		using a five-year average of the annual expense. Accordingly, the projected
3		Vacation Accrual expense reflected on Exhibit A-13, Schedule C5.11, line 16, is
4		based on the average of the recorded expense for the years 2017 through 2021 of
5		\$251,000. This results in an increase to Accrued Vacation expense of \$1.751
6		million. The adjusted five-year average is then escalated by the projected 3.0%
7		labor annual cost increases through the end of the projected test year.
8		
9	Q44.	What is the basis for the Supplemental Severance Plan cost projections?
10	A44.	The Supplemental Severance Plan, which was implemented on July 1, 2016, is
11		designed to address the differences in full benefit eligibility retirement ages
12		between the DTE Traditional Pension Plan and the MCN Energy Group, Inc (MCN)
13		Traditional Pension Plan. As a severance plan, in accordance with the regulations
14		of the U.S. Department of Labor, it is not subject to participation, vesting and
15		funding requirements of ERISA. Eligible employees will receive a lump sum
16		payment equal to the present value of the difference between the DTE Pension Plan
17		and the MCN Pension at the termination of employment. Aon developed the
18		projected cost of this plan, which is estimated to decrease from \$1.079 million in
19		2021 to \$125,000 for the projected test year, as reflected on Exhibit A-13, Schedule
20		C5.11, line 17.
21		
22	Q45.	How did you project the increase in the Company's Wellness Program
23		expense?
24	A45.	As referenced in my discussion of Active Healthcare expense, the Company has a
25		Wellness Program designed to produce significant reductions in future active

Line <u>No.</u>

1		healthcare expense. Wellness Program expense is projected to increase from
2		\$4.556 million in the historical test year to \$5.329 million in the projected test year
3		based on the adjusted healthcare trend annual escalations of 6.0% in 2022, 5.50%
4		in 2023, and 5.00% in 2024 (Exhibit A-13, Schedule C5.11, line 18).
5		
6	Q46.	How have you projected the Company's Long-Term Disability Expense?
7	A46.	Actual 2021 Long-Term Disability Expense is projected to increase from \$1.458
8		million to \$1.589 million during the projected test year based on the assumption
9		that disability claims costs are primarily driven by labor costs escalations, which
10		are assumed to be 3.0% per year between 2021 and the end of the projected test
11		year.
12		
13	Q47.	What is the Supplemental Savings Plan?
14	A47.	The SSP is a non-qualified benefit plan that does not meet the requirements under
15		the Internal Revenue Code to be eligible for certain tax advantages, such as the
16		deductibility by the Company of any contributions. Each year, the Internal
17		Revenue Service (IRS) establishes limitations on employee annual eligible
18		compensation and annual contributions to tax advantaged plans. To the extent an
19		employee's annual eligible compensation or annual contributions, including the
20		Company's match, to the Company's qualified plan exceeds the IRS limitations,
21		employees that are Director level and above are eligible to participate in the SSP.
22		By participating in the SSP, employees accrue benefits that are identical to the
23		benefits available under the qualified savings plan. As such, the SSP is a "make-
24		whole" benefit plan that merely puts the participating employees in the same place
25		they would be in the absence of the IRS limitations.

# Q48. What is the basis for the adjustments to the SSP costs for the projected test year?

4 A48. The decrease in SSP costs from \$3.961 million to \$2.733 million, as shown on 5 Exhibit A-13, Schedule C5.11, line 22, reflects an increase in the Company's 6 matching contributions based on projected salary escalations that is completely 7 offset by a reduction in the expected earnings on designated investments. Since the 8 Company does not separately fund the Company's matches to the employees' 9 contributions, the earnings and losses from the employees' directed investments is 10 a cost incurred by the Company. The SSP projection reflects an annual return on 11 the investments of 6.60% in 2023 and 6.20% in 2024, consistent with the expected 12 long-term return on investments used in the determination of the Company's 13 pension costs in the projected test year. The decrease in SSP expense is based on a 14 projected reduction in the actual return on assets in 2021.

15

### Q49. What is the basis for the adjustments to the Deferred Compensation Plan costs?

18 Similar to the Supplemental Savings Plan, the Company's recorded costs are based A49. 19 on the return on the investment directives of the participating employees since the 20 deferrals are not funded by the Company. Like the SSP, the projected Deferred 21 Compensation Plan costs are based on the expectation that the designated 22 investments will earn an annual return of 6.60% in 2023 and 6.20% in 2024. The 23 decrease in the Deferred Compensation Plan costs from \$151,000 to \$91,000, as 24 reflected on Exhibit A-13, Schedule C5.11, line 23, is based on the reduction from 25 the actual return in 2021 on the investment balances to the assumed returns.

<b>.</b> .		M. S. COOPER
Line <u>No.</u>		0-21297
1		
2	Q50.	How did you develop the projections for the other items included in Other
3		Benefits Costs on Exhibit A-13, Schedule C5.11?
4	A50.	The ACA expense of \$23,000 reflects the actual costs recognized for the
5		Comparative Effectiveness Research Fee and, because the fee as approved in the
6		ACA escalates at the overall national medical expenditures, is escalated at the
7		annual Active Healthcare inflation rates, resulting in \$26,000 of ACA expense for
8		the projected test year. General Benefits Expense and Retirement Administration
9		Fees are projected based on the actual amounts recorded in 2021 of \$2.285 million
10		and \$0.226 million and escalated at the overall rate of inflation as measured by the
11		Consumer Price Index through the end of the projected test year. This results in
12		projected General Benefits Expense of \$2.633 million and Retirement
13		Administration Fees of \$0.260 million.
14		
15	Q51.	What are the Company's total projected employee pensions and benefits
16		expenses for the projected test year?
17	A51.	The total projected employee pensions and benefits expenses of \$126.017 million
18		is reflected on Line 28 of Exhibit A-13, Schedule C5.11. After adjustments for the
19		impact of the portion of these costs to be capitalized and transferred as well as the
20		elimination of costs allocated to the Company's separate surcharge programs, as
21		sponsored by Witness Uzenski, employee pensions and benefits expenses for the
22		projected test year are reduced to \$101.995 million.
23		

#### No.

Line

### 1 LABOR COST ESCALATION

# Q52. What annual labor cost escalation assumptions are appropriate for the projected test period?

A52. Annual labor cost escalation assumptions are required for both the Company's represented and non-represented employees. Based on existing Collective Bargaining Agreements, the Company is obligated to increase pay rates by at least 3.0% annually through the term of the contracts. In addition to scheduled pay rate increases, the agreements also provide for progression increases for those employees that have not yet achieved the maximum pay rate for their positions.

10

11 Non-represented employee compensation is generally adjusted annually based on a 12 review of pay practices of other employers, changes in the external competitive 13 market and internal pay equity. Pursuant to these reviews, the Company 14 implemented base pay adjustments in March 2022 that resulted in an overall pay 15 increase of about 3%, just as it was in 2021 and every year since 2010. In addition 16 to the annual pay adjustment program, employees also receive pay increases based 17 on promotions.

18

Based on the above, I have determined that annual escalations of 3.0% for 2022,
2023, and 2024 are a conservative estimate of the Company's expected increase in
its labor rates.

22

#### 23 EMPLOYEE COMPENSATION

Q53. What is the Company's compensation philosophy and framework for non represented employees other than Executives?

1 A53. Non-represented employees are those employees not covered by any Collective 2 Bargaining Agreements with the Company's union organizations. Compensation 3 for employees covered by Collective Bargaining Agreements is established 4 pursuant to negotiations. Non-executive employees are generally defined as those 5 with titles below Vice President level. DTE Electric's compensation philosophy is 6 to provide pay programs that: 1) attract, retain, and motivate employees; 2) ensure 7 that pay is externally competitive (i.e., paid near market median); and 3) 8 differentiate total rewards based on both organizational unit results and individual 9 contributions.

10

11 At DTE Electric, total annual compensation for all non-represented employees has 12 two primary components: base pay and variable pay, as delivered through the 13 Company's incentive compensation programs. Employee base pay is reviewed 14 annually and adjusted (if appropriate) based on the position relative to what the 15 external market pays for similar positions and individual performance. Variable 16 pay is based on the achievement of Company, as well as departmental and 17 individual results. Variable pay is made up of both short-term incentive and long-18 term incentive plans.

19

# Q54. How does the Company's philosophy regarding incentive compensation compare with that of its peers?

A54. Incentive compensation programs are a component of total compensation practices
 for the vast majority of energy companies for their non-represented employee
 population, as described below. Base pay is set lower than it otherwise would be
 because of the variable pay component. When considered holistically, the

#### Line No.

Line No.

> 1 Company's base and variable pay plans provide a framework of market-based total 2 annual compensation pay opportunities for non-represented employees. It is the 3 total annual cash compensation, as represented by these two components, that prospective and current employees use to gauge whether DTE Electric's 4 5 compensation is competitive with other potential employers. 6 7 Q55. How does the Company's non-represented compensation philosophy and 8 framework benefit customers? 9 A55. DTE Electric's compensation philosophy and framework provides a benefit to 10 customers by attracting and retaining employees with the requisite skills and 11 experience to ensure safe, reliable, and high-quality customer service delivery, and 12 by recognizing and rewarding effective and efficient performance. A competitive 13 compensation policy also serves to effectively retain employees, minimizing the 14 risks and costs of high employee attrition. This philosophy directly benefits all 15 customers by providing a high level of service at a competitive cost and provides 16 incentives to focus future job performance on those activities that provide the most 17 benefit to customers. 18 19 Q56. What is the external comparative market used by the Company to determine 20 the external market for compensation?

> A56. The external comparative market for positions varies based on the specific job.
> Some jobs are compared to those in utilities of similar size (e.g., revenue, number
> of employees, etc.), other jobs are compared to general industry located in
> Southeastern Michigan, and yet other jobs to general industry located within the
> United States. The relevant market will depend upon the requisite skills and

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1		abilities required of the job and the nature of the recruitment source. For example,
2		the comparative market for an administrative assistant is the general industry within
3		Southeastern Michigan while the comparative market for a manager of nuclear
4		operations is utilities within the Midwestern United States (primarily), or within the
5		entire United States (secondarily).
6		
7	Q57.	How is benchmark data obtained from the external comparative market?
8	A57.	The Company participates in and/or purchases published salary surveys from
9		several different organizations. The surveys typically report median base salary,
10		target incentives, and median total cash compensation by job classification.
11		
12	Q58.	How are base salaries determined?
13	A58.	Base salaries are targeted around the median base salary levels of the competitive
14		market as adjusted for differences in company size and scope where appropriate.
15		All non-executive positions are placed in a salary zone based on external
16		benchmarking. The mid-point of the salary zone is based on the market median for
17		comparable work in comparable companies. A range is provided above and below
18		the midpoint to allow for differentiation based on applicable skills and experience,
19		as well as demonstrated performance. The ranges are reviewed periodically to help
20		ensure they remain competitive in the external market.
21		
22	Q59.	Does the Company benchmark the variable component of compensation?
23	A59.	Yes. The Company reviews several surveys that provide information on a number
24		of variable pay indices. In addition, the surveys report data for employee groupings
25		such as exempt employees, non-exempt employees, managers, and executives.

Line No.

1

# Q60. Could an alternate compensation system be structured, eliminating variable components?

Yes. The Company could raise employees' base pay to the market levels for total 4 A60. 5 compensation in lieu of providing variable pay opportunities to maintain a 6 competitive total compensation level. However, this would have several 7 undesirable effects. For example, raising employees' base pay to the total 8 compensation market levels would result in a higher level of fixed costs tied to base 9 salaries, such as certain defined contribution benefit plans, life insurance, disability 10 insurance, and other salary-based employee benefits. Moreover, given the well-11 recognized motivational value of variable pay compensation programs, as 12 described below, delivering employee compensation solely in fixed salary would 13 diminish the performance incentive for employees to provide superior service to 14 customers. Annual incentives ensure that individuals have an element of "at risk" 15 compensation that allows the Company to differentiate pay based on performance 16 and allocate compensation to those employees that are most deserving.

17

### 18 **EXECUTIVE COMPENSATION**

# 19 Q61. How does the compensation program for executives differ from that for non 20 executives?

A61. The compensation program for executives differs in three respects. First, the comparative market for compensation benchmarking is defined as a specific group of peer companies from which data are obtained through a custom study generally performed every two years. Second, a higher proportion of executives' compensation is delivered in the form of variable pay. The third way in which the

Line <u>No.</u>		U-21297
1		executive compensation program differs is with respect to governance. The
2		compensation programs for Company executives must be approved by the
3		Organization and Compensation Committee of the DTE Energy Board of Directors.
4		
5	Q62.	What is the comparative market for executive compensation?
6	A62.	The comparative market used by DTE Energy for determining the alignment of its
7		executive compensation programs with similar companies consists primarily of
8		utilities (including utility holding companies) and broad-based energy companies
9		selected on the basis of revenues, financial performance, geographic location, and
10		availability of compensation information.
11		
12	Q63.	What are the key components of the Executive Compensation Program?
13	A63.	The key elements of the Executive Compensation Program are base salary and
14		variable pay (annual incentive plan and long-term incentive awards).
15		
16	Q64.	How are base salaries determined?
17	A64.	Base salaries are targeted around the median of the comparative market.
18		Appropriate methods of measurement are used to take into account differences in
19		company size and scope. In addition, midpoints are established for those executives
20		whose jobs cannot be easily matched in the comparative market. These midpoints
21		are assessed periodically to keep pace with market movement and are designed to
22		allow adequate differentiation for 1) individual potential, 2) contributions made,
23		and 3) the length of time the executive has been in his or her position.
24		

1	COMPETITIVE COMPENSATION ANALYSIS		
2	Q65.	Has the Company prepared an analysis of its compensation practices relative	
3		to the market medians?	
4	A65.	Yes. DTE Electric has performed an analysis of virtually all incumbent salaries as	
5		of December 31, 2021, showing that DTE's compensation practices are competitive	
6		with market medians. Exhibit A-21, Schedule K1 reflects a summary of the market	
7		median for all DTE Electric positions for which corresponding positions have been	
8		identified, other than those employees covered by collective bargaining	
9		agreements. In addition, Exhibit A-21, Schedule K1 reflects those positions at DTE	
10		LLC that primarily support DTE Electric. Exhibit A-21, Schedule K1 reflects	
11		employee compensation information organized based on Career Family	
12		classifications used by DTE Electric. A Career Family is a grouping of jobs based	
13		on similar skill requirements and job content in a specialized discipline (i.e.,	
14		Finance, Engineering, Information Technology, etc.) that may or may not fit into a	
15		business unit organizational structure. For example, Engineering or Finance Career	
16		Families could exist in several organizational units.	
17			
18	Q66.	How is an analysis of a competitive pay structure performed?	
19	A66.	An analysis of market-based pay structure is performed by identifying comparable	
20		positions and determining the compensation ranges paid by similar employers in	
21		relevant locations. A more expansive description of the means of assessing a	
22		competitive pay structure is provided in an article published by Salary.com, entitled	
23		The Basics of Market Pricing a Job (January 26, 2017).	

24

1	Q67.	Is the Company's use of a market pricing approach to employee compensation
2		consistent with others?
3	A67.	Yes. According to a recent survey performed by WorldatWork and Deloitte
4		Consulting, entitled 2019 Survey of Salary Structure Policies and Practices, more
5		than half of the companies surveyed use a market pricing model for setting
6		compensation levels.
7		
8	Q68.	Why are employees covered by collective bargaining agreements excluded
9		from this analysis?
10	A68.	Compensation levels for unionized employees are determined through a negotiated
11		process, which involves a variety of work rules and benefit related issues, rather
12		than determined strictly through market analysis. Moreover, the specialized skills
13		and experience required by many of the positions are not readily comparable to
14		other positions in the local market. Thus, a comparison of pay levels for those
15		employees covered by collective bargaining agreements is not useful in this
16		context.
17		
18	Q69.	What conclusions can be drawn from Exhibit A-21, Schedule K1?
19	A69.	In summary, Exhibit A-21, Schedule K1 demonstrates that the weighted average of
20		the annual base compensation for all positions with incumbents as of December 31,
21		2021, with available position matches was a mere $0.3\%$ higher than the average of
22		median market base compensation. Plus, this analysis further demonstrates that
23		total cash compensation for all positions with incumbents as of December 31, 2021,
24		with available position matches was 1.0% less than the average of median market
25		for total cash compensation. This analysis concludes that the Company's total

Line No.

> 1 compensation is insignificantly different from the market medians and confirms 2 that the Company's compensation practices are consistent with the Company's 3 compensation policy to pay employees near the market median for comparable 4 positions on a total cash compensation basis. Moreover, a comparison of the 5 Company's base salaries, which excludes short-term incentive compensation, to the 6 market medians for total cash compensation, which is inclusive of short-term 7 incentive compensation, shows that in the absence of the Company's short-term 8 incentive compensation programs, the Company's pay would be 11.8% less than 9 the market medians.

10

#### 11 Q70. How was the market median for the positions determined?

12 As described above, the Company subscribes to several compensation survey A70. 13 providers that create comprehensive databases of job descriptions that enables the 14 Company to match the job requirements, including education, expertise and 15 experience of existing positions with market surveys. After matching job positions 16 are identified, actual base and total compensation ranges are developed from the 17 salary survey database. The information on Exhibit A-21, Schedule K1 was derived 18 from the Company's compilation of the compensation for positions with an 19 incumbent as of December 31, 2021.

20

# Q71. What proportion of DTE Electric's total employee population as of December 31, 2021, is reflected in this analysis?

A71. This analysis includes 99.5% of the employee population as of December 31, 2021,
at DTE Electric, as well as DTE LLC employees that provide supporting services

Line <u>No.</u>		<b>M. S. COOPER</b> U-21297
1		to DTE Electric. This is exclusive of those employees represented by collective
2		bargaining agreements.
3		
4	Q72.	What is included in the total cash compensation amounts?
5	A72.	Total cash compensation reflects base pay as of December 31, 2021, and the Target
6		payout levels for those employees eligible to participate in the Company's short-
7		term incentive compensation programs. Although the analysis on Exhibit A-21,
8		Schedule K1 does not reflect the value of the Company's Long-Term Incentive
9		Plan, as it is primarily for executive level positions, a separate analysis of executive
10		compensation prepared by Aon, which is inclusive of long-term plans, shows that
11		total compensation is about 9% less than the median of the Company's peer group,
12		as discussed in more detail below.
13		
14	INCE	NTIVE COMPENSATION
15	Q73.	What are you proposing regarding the level of incentive compensation expense
16		to be included in the Company's revenue requirement?
17	A73.	I am proposing that the projected incentive compensation expense of \$62.903
18		million related to the Company's short-term and long-term incentive compensation
19		plans be included in the revenue requirement adopted by the Commission in this
20		proceeding, as described in more detail below. The components of the projected
21		\$62.903 million of incentive compensation expense are detailed in Table 4 reflected
22		in response to Q100.
23		
24	Q74.	Is the Company requesting recovery in rates for all incentive compensation
25		expenses?

1	A74.	No. While the Company's compensation expenses are reasonable, \$11.7 million of
2		incentive compensation expense related to DTE Energy's Top Five Executive
3		Officers has been excluded. This exclusion is reflected on Exhibit A-3, Schedule
4		C19 as supported by Witness Uzenski and has been excluded from Table 4 reflected
5		in the response to Q100.
6		
7	Q75.	What is the basis for your proposed inclusion of \$62.903 million of incentive
8		compensation expense in the Company's revenue requirement?
9	A75.	In summary, my proposal to include all the Company's projected incentive
10		compensation expense, exclusive of the portion related to the Top Five Executive
11		Officers, is based on the prevalence of incentive compensation programs and the
12		resultant need for the Company to have total compensation programs that enable it
13		to be competitive with other employers. As described above, the Company's
14		existing total cash compensation is in line with the market, as is the total
15		compensation for its executives. Moreover, in the absence of the incentive
16		compensation programs, total cash compensation for the Company's employees
17		would be almost 12% less than the market medians, as reflected on Exhibit A-21,
18		Schedule K1, and total compensation for its executives would be 70% less than
19		market, as reflected in Table 3 below in Q81. The remainder of my testimony will
20		demonstrate that the Company's incentive compensation programs are both
21		reasonable and prudent and, therefore, a necessary cost of the Company doing

23

22

Q76. Are there any employee motivational advantages to including an incentivebased compensation component in a company's overall compensation design?

business that should be reflected in the Company's revenue requirements.

Line <u>No.</u>

<u>.</u>		
1	A76.	Yes. The underlying principle of incentive compensation plans is to motivate
2		improved organizational performance. An effective incentive compensation plan
3		provides a "pay-for-performance" environment intended to motivate individual and
4		team achievement of measurable goals.
5		
6	Q77.	Is there any evidence that incentive-based compensation is effective in
7		motivating improved organizational performance?
8	A77.	Yes. A comprehensive analysis of the impact of incentive compensation plans on
9		organizational performance concluded that programs that provide tangible
10		incentives for achievement of certain goals lead to a 27% increase in organizational
11		performance (Incentives, Motivation and Workplace Performance: Research &
12		Best Practices, The International Society for Performance Improvement, Spring,
13		2002). This study observes that the source for such organizational performance
14		improvements is that employees 1) value their work tasks more, 2) have more self-
15		confidence and esteem for their employers, 3) are more persistent at work tasks,
16		and 4) strive for high levels of accomplishments. Moreover, this study notes that
17		long-term incentive plans provide even greater performance improvements. In
18		addition, an Aon study of Variable Compensation Measurement Survey issued in
19		2018 reported that 86% of participants in the survey indicated that their variable
20		compensation plans resulted in improved business results.
21		

- Q78. Are incentive compensation programs a typical element in compensation at
  other companies?
- A78. Yes. According to a 2021 study published by WorldatWork and Compensation
  Advisory Partners, most companies had both short-term and long-term incentive

Line No.

programs (Incentive Pay Practices: Publicly Traded Companies, July 2021,
 WorldatWork and Compensation Advisory Partners). Moreover, a 2018 study by
 Aon of U.S. Salary Increases shows that 90% of Power and Gas Service providers
 utilized broad-based incentive compensation programs.

5

### Q79. Do the Company's incentive compensation plans result in unreasonable compensation?

8 A79. No. As explained above, the Company benchmarks its total compensation for non-9 represented employees against relevant peers, inclusive of incentive compensation, 10 and establishes a mid-point salary range based on the median market level. 11 Moreover, based on a recent survey by Aon, the total compensation of DTE 12 Energy's Executives is about eight percent less than the median of its peers based 13 on Target level performance, inclusive of the long-term incentive compensation. 14 The Company's incentive compensation programs are merely a component of the 15 total compensation policies required for the Company to be competitive with its 16 peers, rather than a supplement. Additionally, DTE Energy's Executives 17 compensation would be substantially less than its peers, since about 70% of total 18 compensation is delivered through short and long-term incentive compensation 19 programs, by both DTE Energy and its peers.

20

# Q80. How do the components of the Company's total Executive compensation practices compare to the Company's peers?

A80. Based on the Aon survey referenced above, a comparison of the relative magnitude
of the Company's salary, short-term and long-term pay components for Executives
to the 50th percentile of its peers is reflected in Table 3.



Line
U-2

1	A82.	The AIP is a short-term variable pay program available to senior management level
2		employees to motivate performance. The 2022 AIP measures and weightings for
3		DTE Electric, other than Nuclear Generation, DTE Nuclear Generation, and DTE
4		Energy Corporate Services LLC are reflected on Exhibit A-21, Schedules K2, K3
5		and K4, respectively. For each measure, a Target is established for which a 100%
6		payout will be earned. Performance less than Target, but above a minimum
7		Threshold, results in a payout between 25% of Target and 100%, a payout of 100%
8		of Target when performance is at Target, and performance between Target and the
9		Maximum level results in a payout of up to 175% of Target for non-executive
10		participants of the AIP and up to 200% of Target for Executive participants of the
11		AIP.
12		
13	Q83.	Which employee classifications are eligible to participate in the AIP?
14	A83.	All Executive level employees, generally those with titles of Vice President and
15		above, and Directors participate in the AIP. All other non-represented employees
16		are eligible to participate in the REP.
17		
18	Q84.	What are the components of the REP?
19	A84.	The REP is identical to the AIP except that Threshold performance is at 50% of
20		Target and the Maximum performance payout is 150% of Target. The 2022 REP
21		measures and weightings are reflected on Exhibit A-21, Schedules K2 through K4.
22		The REP measures are identical to the AIP measures other than the REP excludes
23		the Gallup survey of employee engagement measure in recognition that the
24		Company's leadership is responsible for providing an environment of high employee
25		engagement.

Line <u>No.</u>			<b>M. S. COOPER</b> U-21297
1			
2	Q85.	What	are the categories of measures included in the AIP and REP?
3	A85.	There	are four categories of measures in both the AIP and REP. Specifically,
4		Financ	cial Performance, Customer Satisfaction, Safety and Engagement, and
5		Operat	ting Excellence.
6			
7	Q86.	What	are the financial measures included in the AIP?
8	A86.	There	are three financial measures for DTE Electric employees that are designed to
9		create	a clear line of sight for all employees to focus on operating excellence by
10		reward	ling employees when the Company is successful.
11		1)	DTE Electric Operating Earnings objective is based on the Company
12			realizing the authorized return on equity by the Commission in its Order in
13			Case No. U-20561.
14		2)	DTE Electric's Cash from Operations is similarly based on the authorized
15			return on equity but is adjusted for non-cash items. The inclusion of a cash
16			flow measure recognizes the importance of DTE Electric maintaining a high
17			credit rating to allow continued access to the capital markets at reasonable
18			costs and terms to ensure sufficient capital investment to continue to serve
19			our customers.
20		3)	DTE Energy's Earnings per Share measure is based on the midpoint of 2022
21			earnings guidance.
22		Nuclea	ar Generation Financial Performance measures consist of DTE Electric
23		Operat	ting Earnings and Nuclear Generation Operation and Maintenance Expense.
24		The F	Financial Performance measures for DTE LLC reflect DTE Energy's
25		Operat	ting Earnings per Share and Cash from Operations.

### MSC-45

Line <u>No.</u>		U-21297
1		
2	Q87.	What are the Customer Satisfaction measures?
3	A87.	There are two customer satisfaction measures that are intended to focus employees
4		on improving the experience that our customers have in their interactions with the
5		Company. The measures are:
6		1) The Net Promoter Score (NPS) is a measure of the extent to which
7		customers are likely to recommend the Company to their friends and
8		colleagues. The Target in 2022 is 39, which is 4 points higher than the
9		actual NPS in the fourth quarter of 2021.
10		2) The MPSC Customer Complaints measure represents the number of formal
11		complaints made to the MPSC regarding both DTE Electric and DTE Gas,
12		as reported to the Company by the MPSC. The combined Target in 2022 is
13		1,873 compared to 2,828 in 2021.
14		
15	Q88.	What are the measures related to Safety and Engagement?
16	A88.	The three Safety and Engagement measures encompass employee engagement as
17		measured by the Gallup survey and two employee safety related measures.
18		
19	Q89.	What is the measure related to Employee Engagement?
20	A89.	The Gallup measure of Employee Engagement is reflective of the direct correlation
21		between the level of active employee engagement and the performance of an
22		organization. The 2022 Target of 4.32 is a grand mean of the results of the Gallup
23		surveys of employees, which represents 92 <sup>nd</sup> percentile performance compared to
24		other companies that participate in the Gallup surveys. Employee Engagement is a

		M. S. COOPER
Line <u>No.</u>		U-21297
1		statistically significant measure of the level of commitment employees have to an
2		organization's success and is not merely a measure of employee satisfaction.
3		
4	Q90.	What are the Safety related measures?
5	A90.	DTE Electric has two safety related measures.
6		1) The first is the OSHA Recordable Injury Rate (RIR), which measures the
7		recordable injuries per 100 employees divided by the actual number of hours
8		worked, as defined by the Occupational Safety and Health Administration
9		(OSHA). This is a standard measure of safety performance used nationwide.
10		The measure is intended to create a heightened focus on the importance of
11		safety in the workplace. The RIR Target for 2022 is .53 compared to the actual
12		.68 RIR in 2021.
13		2) The second is High Energy Serious Injury or Fatality (HSIF), which is a
14		measure adopted by the Edison Electric Institute that recognizes the degree of
15		seriousness of an injury in the context of a dangerous event. The 2022 Target
16		of 3 is based on an improvement from the five-year average of 4.
17		
18	Q91.	What are the Operating Excellence measures for 2022?
19	A91.	DTE Electric has four Operating Excellence measures that reflect specific operating
20		priorities for 2022 to motivate the achievement of certain operating objectives
21		important to the Company, its customers, and the Commission. Two of these
22		measures relate to Distribution System Reliability and the other two relate to
23		Generation Reliability.
24		
25		The two Electric Distribution Reliability Measures are:

Line			<b>M. S. COOPER</b> U-21297
<u>1 1</u>		1)	The System Average Interruption Duration Index (SAIDI) exclusive of
2			Major Event Days (MEDs). The 2022 Target is 129 minutes. This
3			compares to the 2021 actual of 136 minutes.
4		2)	The percentage of customers that experience four interruptions or more
5			(CEMI4) in a calendar year. The Target in 2022 is 7.55%. This compares
6			to the 2021 actual of 12.2%
7			
8		The tw	o Generation Reliability Measures are:
9		1)	The percentage of hours that DTE Electric's coal, gas, and renewable plants
10			are mechanically available to produce power. The 2022 Target is 83.2%.
11			This compares to a four-year average of 82.1%
12		2)	Nuclear On-Line Reliability Loss Factor (ORLF), which is energy
13			generation losses corrected for refueling outage losses and exempt
14			activities. The 2022 ORLF Target is 1.12% compared to 2021 actual of
15			3.68%.
16			
17	Q92.	What	are the operating measures applicable to the Nuclear Generation
18		busin	ess unit?
19	A92.	Nucle	ar Generation has three Safety and Engagement related measures and five
20		Opera	ting Excellence measures, discussed below in further detail.
21			
22	Q93.	What	are Nuclear Generation's Safety and Engagement related measures?
23	A93.	In add	dition to Employee Engagement, as measured by Gallup surveys, and the
24		OSHA	A Recordable Incident Rate, which have been described in the context of DTE
25		Electr	ic, Nuclear Generation also uses the annual Total Industrial Safety Accident

Line No.		<b>M. S. COOPER</b> U-21297
1		Events (TISA Events), which is a nuclear industry measure that is aligned with the
2		Institute of Nuclear Power Operations (INPO). The Threshold is one incident, and
3		the Maximum is zero.
4		
5	Q94.	What are the Operating Excellence measures related to Nuclear Generation?
6	A94.	Nuclear Generation has five Operating Excellence measures.
7		1) The first relates to On-Line Reliability Loss Factor, as described above.
8		2) The second measure pertains to a group of 11 measures that relate to Fermi
9		2 plant performance.
10		3) The third measure is an index of Annualized Work Management, which
11		consists of 10 individual indicators.
12		4) The fourth measure is the Radiation Protection index related to seven
13		specific indicators.
14		5) The final Nuclear Generation measure relates to the Nuclear Refuel Outage
15		Performance Matrix.
16		
17	Q95.	Are there other AIPs and REPs that impact DTE Electric's expenses?
18	A95.	Yes. In addition to the DTE Electric and Nuclear Generation measures described
19		above, there are also AIPs and REPs in place for corporate staff employees at DTE
20		LLC that provide services to all DTE Energy business units, including DTE
21		Electric. The measures of the DTE LLC reflect certain DTE Electric and Nuclear
22		Generation measures, as well as measures related to DTE Gas. The specific DTE
23		LLC measures and weightings related to DTE Electric and Nuclear Generation are
24		reflected on Exhibit A-21, Schedule K-4.
25		

1	Q96.	What is the Company's Long-Term Incentive Plan?
2	A96.	The LTIP provides the opportunity for certain individuals to receive retention-
3		oriented or performance-based rewards delivered via shares of DTE Energy
4		common stock, either Performance Shares, which are based on the achievement of
5		multi-year performance objectives, or through Restricted Stock. Currently, 70% of
6		the value of awards for executives and directors is through grants of Performance
7		Shares and 30% of the value of awards is through Restricted Stock, while 100% of
8		the awards to other eligible employees are through Performance Shares. The
9		objective in granting shares through this program is to both motivate superior
10		results as well as provide a means to retain key employees and is consistent with
11		the practices of 88% of surveyed companies, as reflected in the WorldatWork and
12		Compensation Advisory Partners survey, referenced above.
13		
14	Q97.	What are the 2022 performance share measures used in the LTIP?
15	A97.	The measures are shown on Exhibit A-21, Schedule K5.
16		
17	Q98.	What is the rationale for the use of these measures?
18	A98.	These measures generally reflect the long-term financial performance of DTE
19		Energy and are intended to motivate employees of the individual operating
20		companies, such as DTE Electric, to keep in mind the role of their own
21		contributions to the overall long-term success of DTE. Accordingly, the
22		predominate measure for DTE Electric and DTE LLC (80% for both) is the total
23		return to DTE Energy shareholders (i.e., capital appreciation and dividends)
24		relative to a group of peer companies over the next three years. The second
25		financial measure included in the LTIP, that contributes 20% to the weighting, is

Line <u>No.</u>

1 DTE Energy's three-year cumulative Operating Earnings per Share. The three-year 2 focus of the performance-based measures is designed to motivate decisions and 3 actions that produce sustainable benefits rather than short-term actions that may 4 entail long-term risks. 5 6 The LTIP also includes two operating measures for Nuclear Generation that relate 7 to a standard industry INPO index measuring nuclear power plant performance and 8 the Nuclear On-Line Reliability Loss Factor, which have weightings of 60% and 9 20% respectively. The third Nuclear Generation measure relates to DTE Energy's 10 total return to shareholders and is weighted 20%. 11 12 Q99. What is the basis for the costs of the LTIP? 13 A99. The LTIP costs incurred in 2021 pertain to the grants of Performance Shares and 14 Restricted Stock. The expense related to the Restricted Stock is not conditioned on 15 any Company performance measures but rather is exclusively based on the number 16 of shares granted at the date of grant. In contrast, Performance Shares expense is 17 based on the achievement of the predetermined performance objectives. The 18 recognized cost of Performance Shares is based on the number of shares granted at 19 the market price of DTE Energy's common stock at the date of grant but with 20 adjustment in the number of shares based on actual performance. Witness Uzenski 21 describes the adjustment to the actual 2021 LTIP expense to normalize for the 22 impact of changes in DTE Energy's stock price recognized in 2021. 23 24 **Q100.** What is the incentive compensation expense if all the Operating Targets are

25 achieved?

Line

No.

A100. The net expense to DTE Electric in the projected test period of the Company
achieving all its Targets for the incentive compensation plans, exclusive of the
expense related to the Top Five Executive Officers, is \$62.903 million. The table
below summarizes the expense for the projected test period by the nature of the
plans, the classification of the employees eligible and the basis of the metrics used.

6

7

8

Table 4

	LTIP	AIP	<u>REP</u>	<u>Total</u>
		(000's On	nitted)	
Financial				
DTE Electric	\$7,559	\$566	\$6,943	\$15,068
Nuclear Gen	106	97	783	986
DTE LLC	17,148	4,052	6,145	27,345
	24,812	4,716	13,871	43,399
Operating				
DTE Electric	0	457	5,600	6,056
Nuclear Gen	422	237	2,719	3,378
DTE LLC	0	4,001	6,069	10,070
	422	4,694	14,387	19,504
Total				
DTE Electric	7,559	1,023	12,543	21,124
Nuclear Gen	528	334	3,502	4,364
DTE LLC	17,148	8,053	12,214	37,414
	\$25,234	\$9,410	\$28,258	\$62,903

#### 9 Q101. Why are the expenses for DTE LLC most of the incentive compensation

10 expenses?

A101. DTE LLC provides a variety of administrative and other services that are common
 to both DTE Electric and DTE Gas for which the costs are billed to the operating

		M. S. COOPER
Line <u>No.</u>		U-21297
1		companies, as explained by Witness Uzenski. In addition, DTE LLC employs all
2		the Executives of DTE Energy, including the Officers of DTE Electric.
3		
4	Q102.	How have you reflected the Operating Excellence measures related to DTE
5		Gas in the AIP and REP for DTE LLC?
6	A102.	While the AIP and REP expenses allocated to DTE Electric in the historic period
7		from DTE LLC include some measures related to DTE Gas, the AIP and REP
8		weightings for DTE LLC have been adjusted to exclude the measures specifically
9		related to DTE Gas.
10		
11	Q103.	Are all incentive compensation costs dependent on the Company's financial or
12		operating performance?
13	A103.	No. As described earlier, a portion of the DTE Energy shares granted under the
14		LTIP are in the form of Restricted Stock. Unlike the Performance Shares, the
15		expense of Restricted Stock is not variable based on either the Company's financial
16		or operating performance. The only contingency is that the employee forfeits the
17		Restricted Stock if they leave the Company, other than through retirement or the
18		event of the employee's death or disability.
19		
20	Q104.	How does the lack of variability in the LTIP expense affect its treatment in
21		your analysis of incentive compensation?
22	A104.	Although Restricted Stock grants are made under the LTIP, the ultimate payouts
23		are not dependent on future Company or employee performance, and therefore,
24		Restricted Stock is not regarded as an element of the Company's incentive

Line No.	M. S. COOPER U-21297
1	compensation expense. Accordingly, the projected test year Restricted Stock
2	expense of \$6.534 million has been excluded from Table 4 above.
3	
4	Q105. Has the Commission provided any criteria for the inclusion of incentive
5	compensation expense in the Company's revenue requirements?
6	A105. Yes. The Commission has indicated in all its recent Orders addressing incentive
7	compensation programs that inclusion of incentive compensation expense in a
8	company's revenue requirement was dependent on a showing that the incentive
9	compensation programs provided benefits to customers in excess of the expense.
10	
11	Q106. Has the Company performed an analysis of the customer benefits of the
12	Company's incentive compensation plans?
13	A106. Yes. The Company has performed a comprehensive analysis of the customer
14	benefits that would be derived from the achievement of the financial and operating
15	metrics included in the Company's short and long-term incentive plans relative to
16	their expense. This analysis, as reflected on Exhibit A-21, Schedule K6,
17	demonstrates that the calculated aggregate benefit of \$87.947 million exceeds the
18	total incentive compensation expense of \$62.903 million by \$25.044 million.
19	
20	Q107. How are the benefits of the Company achieving Target performance reflected
21	on Exhibit A-21, Schedule K6 determined?
22	A107. The benefits of the measures are computed based either on the avoided costs to the
23	Company, which results in lower future revenue requirements, or based on the
24	value to customers of improved performance. The reference points to determine
25	improvement are, in most instances, based on the Company's actual performance

1		in the 2021 historical test year, but when 2021 results are not representative, either
2		an historical average or a comparison to a peer group is used. In those instances,
3		in which the Company's Targets are based on superior performance relative to
4		peers, then measures of peer performance are used. The benefits of achieving
5		Target performance are allocated between the AIP, REP and LTIP components
6		based on the relative incentive compensation expense for each measure.
7		
8	Q108.	How did you calculate the interest cost savings from the retention of the
9		Company's existing debt ratings?
10	A108.	The DTE Electric Cash From Operations measure within the AIP and REP, as
11		reflected on line 10 of Exhibit A-21, Schedule K6, is focused on the Company
12		maintaining its A debt rating from Standard & Poor's and comparable ratings by
13		the other major debt rating firms. The yield spread between utility bonds for bonds
14		with an A rating compared to BBB rated bonds is 27 basis points. Based on the
15		long-term debt balances included in the capital structure sponsored by Company
16		Witness Vangilder, a downgrade in the Company's credit rating would increase the
17		Company's annual interest costs by \$24.0 million
18		
19	Q109.	How did you quantify the benefit of achieving Target performance levels in
20		the Customer Satisfaction measures?
21	A109.	The benefits of achieving the 2022 Target of 39 Net Promoter Score (NPS) are
22		based on the expectation that improvements in the NPS score will result in fewer
23		customer calls. The 2022 Target of 39 represents a 11% improvement relative to
24		the actual NPS of 35 for the fourth quarter of 2021 and is expected to produce \$2.1
25		million of customer benefits based on avoided Company costs and customer costs.

2

3

4

The customer benefits of attaining Target performance for MPSC Customer Complaints measure is based on the avoided costs to both the Company and its customers due to the reduced time spent by employees and customers resolving complaints for a total savings of \$0.2 million

6

5

While the total quantified benefits of \$2.4 million related to the Customer
Satisfaction measures are slightly less than the related expense, there can be little
doubt that an emphasis among the Company's employees on improving the
experiences customers have with the Company results in additional significant nonquantifiable benefits to both customers and the Commission.

12

#### 13 Q110. How did you determine the benefits of the Employee Engagement measure?

14 A110. The quantifiable benefits of a highly engaged workforce are based on three critical 15 dimensions identified by Gallup: absenteeism, productivity, and safety incidents. 16 According to Gallup, a 0.1 improvement in the grand mean will result in a 3.1% 17 reduction in absenteeism, a 1.8% increase in productivity, and a 3.8% reduction in safety incidents. Compared to the 83<sup>rd</sup> percentile of Gallup survey results for all 18 19 companies included in Gallup's database, which is significantly better than top 20 quartile performance, the achievement of the 2022 Target Gallup survey results will 21 generate O&M savings at DTE Electric of \$20.4 million, inclusive of savings 22 allocated from DTE LLC and net of the savings capitalized.

23

# Q111. What are the expected benefits of the Company achieving Target level performance regarding the OSHA Recordable Incident Rate (RIR)?

1	A111. The benefits of achieving the OSHA Recordable Incident Rate (RIR), and the
2	Nuclear Total Industrial Safety Accident Rate goal, are based on the estimated
3	direct costs of non-fatal incidents of \$44,000, as developed by OSHA. Additionally,
4	a study by Liberty Mutual estimates the indirect cost of an OSHA recordable
5	incident is about 3.0 times the direct costs, resulting in an estimated total cost of
6	\$169,000 per incident, in current dollars. Based on Target level performance,
7	relative to the Company's five-year average results in an estimated benefit of
8	\$980,000 net of the savings capitalized. Because the benefits of achieving the
9	OSHA RIR Target includes all OSHA recordable injuries, the OSHA RIR benefit
10	is allocated equally to both OSHA RIR and HSIF safety measures.

11

12 While the quantified savings of the safety related metrics are less than the related 13 costs, much like the customer service-related measures, the benefits of maintaining 14 an organizational focus on the safe operation of the Company's system for the 15 benefit of its employees, customers, and the communities where the Company 16 operates are undoubtedly substantial.

17

#### 18 Q112. How did you quantify the savings related to improvements in distribution 19 system reliability?

20 A112. The benefit of achieving the 2022 SAIDI Excluding MEDs of 129 minutes is based 21 on comparing the 2022 Target to the 2021 SAIDI Excluding MEDs of 136 minutes, 22 which represents a reduction of seven minutes. The derivation of the benefits to 23 customers was determined based on the Interruptions Cost Estimation Calculator 24 as developed by Nexant, Inc. and the Lawrence Berkeley National Lab. A 25 reduction of seven minutes in the SAIDI excluding MEDs produces an annual

#### Line No.

MSC-57

10.		
1		customer benefit of \$24.7 million. The benefits of achieving Target performance
2		in the SAIDI excluding MEDs measure have been allocated equally between the
3		SAIDI exclusive of MEDs measures and CEMI4 Percent of Customers measure
4		due to the close relationship of each of these measures to distribution system
5		reliability.
6		
7	Q113.	How did you quantify the benefits of the Generation Availability measure?
8	A113.	The benefit of the Generation Availability measure reflects the impact of increasing
9		the overall generation availability to the 2022 Target 83.2% from the three-year
10		average of actual Generation availability of 79.6%. The savings computed reflect
11		the impact of the increases in power generation relative to the avoided market
12		energy purchases and increased capacity value. This produces annual savings of
13		\$5.3 million.
14		
15	Q114.	What are the benefits of an increase in the Nuclear On-Line Reliability Loss
16		Factor?
17	A114.	The benefits of an increase in the Nuclear Power Plant Reliability reflect an increase
18		from the On-Line Reliability Loss Factor at Fermi 2 from the 2021 actual of 3.68%
19		to the 2022 Target of 1.12%. The savings computed are based on the differential
20		between Fermi 2's marginal fuel costs and the average market price of avoided
21		energy purchases combined with increased capacity value for a total annual savings
22		of \$10.1 million. These savings are allocated to the Nuclear related operating
23		measures included in the LTIP (a savings of \$0.7 million) and the AIP and REP
24		measures (a savings of \$9.4 million) in proportion to the costs of each measure.
25		

1	Q115.	Have you quantified any additional savings related to the other Nuclear
2		Generation measures included in the AIP and REP and the INPO Index
3		included in the Nuclear LTIP?
4	A115.	No. The Nuclear On-Line Reliability Loss Factor measure represents the only
5		quantifiable benefits of the Company meeting its Target performance levels for
6		Fermi 2. While there is indisputable value in the various specific measures within
7		the other Nuclear measures, the benefits of Fermi 2 achieving its On-Line
8		Reliability Loss Factor Target has been attributed to the other AIP and REP Nuclear
9		measures and the INPO measure included in the Nuclear LTIP.
10		
11	Q116.	What is your conclusion regarding the cost effectiveness of the Company's
12		incentive compensation plans?
13	A116.	As reflected on Exhibit A-21, Schedule K-6, it is clear the quantified customer
14		benefits of the Company achieving Target performance levels are substantially
15		greater than the related expense.
16		
17		Because the Company's overall employee compensation approximates the market,
18		inclusive of incentive compensation and the quantified benefits exceed the
19		projected incentive compensation expense, the Company's total incentive
20		compensation expense should be included in the revenue requirement adopted by
21		the Commission in this proceeding as a reasonable and prudently incurred expense.
22		
23	Q117.	Does this complete your direct testimony?
24	A117.	Yes, it does.

# STATE OF MICHIGAN

## BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)
DTE ELECTRIC COMPANY	)
for authority to increase its rates, amend	)
its rate schedules and rules governing the	)
distribution and supply of electric energy, and	)
for miscellaneous accounting authority.	)

Case No. U-21297

# QUALIFICATIONS

### AND

### DIRECT TESTIMONY

OF

### JEFFREY C. DAVIS

# DTE ELECTRIC COMPANY QUALIFICATIONS AND DIRECT TESTIMONY OF JEFFREY C. DAVIS

### Line <u>No.</u>

1	Q1.	What is your name, business address and by whom are you employed?
2	A1.	My name is Jeffrey C. Davis (he/him/his). My business address is: 6400 North Dixie
3		Highway, Newport, Michigan, 48166. I am employed by DTE Electric Company at
4		the Fermi 2 Nuclear Power Plant as Expert - Nuclear Strategic Business Operations.
5		
6	Q2.	On whose behalf are you testifying?
7	A2.	I am testifying on behalf of DTE Electric Company (Company or DTE Electric).
8		
9	Q3.	What is your educational background?
10	A3.	I graduated from the University of Michigan with bachelor's degrees in nuclear
11		engineering and radiological sciences (NERS) and engineering physics. I have also
12		earned a master's degree and doctorate in NERS from the University of Michigan.
13		
14	Q4.	Please summarize your professional experience.
15	A4.	I have been employed by DTE Energy since 2008. Prior to my current position, I
16		was Manager - Nuclear Strategy and Business Support with responsibility for
17		developing the strategic financial plan and goals for the Nuclear Generation
18		organization. From 2008-2015, I was a principal financial analyst with
19		responsibility for budgeting, forecasting, and reporting operations and maintenance
20		(O&M) and capital expenditures for the Nuclear Generation organization.
21		
22	Q5.	Do you hold any certifications or are you a member of any professional
23		organizations?
24	A5.	I am a member of the American Nuclear Society.
25		

			J. C. DAVIS
Line <u>No.</u>			U-21297
1	Q6.	What are yo	ur current duties and responsibilities?
2	A6.	I am responsi	ble for advancing the strategic financial and operational plan and goals
3		for the Nucle	ar Generation organization.
4			
5	Q7.	Have you pr	reviously sponsored testimony before the Michigan Public Service
6		Commission	(MPSC or Commission)?
7	A7.	Yes. I have s	sponsored testimony in the following cases:
8		U-20203	2018 Power Supply Cost Recovery (PSCR) Reconciliation
9		U-20528	2020 PSCR Reconciliation
10		U-20162	2018 DTE Electric Rate Case
11		U-20561	2019 DTE Electric Rate Case
12		U-20836	2022 DTE Electric Rate Case

# 1 **Purpose of Testimony**

2	<b>Q8.</b>	What is the	e purpose of you	ur testimony?
3	A8.	The purpose	e of my testimo	ony is to discuss and support the reasonableness of the
4		Company's	actual nuclear	· O&M and capital expenditures for the 12-month
5		historical te	est period ended	December 31, 2021. I will also discuss and support the
6		reasonablen	less of the proj	ected nuclear O&M and capital expenditures for the
7		bridge forec	cast period and th	he 12-month projected test period ending November 30,
8		2024. In ad	ldition, I will di	scuss and support the reasonableness of the projected
9		Nuclear Sur	charge for the p	rojected test period ending November 30, 2024.
10				
11	Q9.	Are you sp	onsoring any ex	whibits in this proceeding?
12	A9.	Yes. I am sj	ponsoring the fo	llowing exhibits:
13		<u>Exhibit</u>	<u>Schedule</u>	Description
14		A-12	B5.3	Projected Capital Expenditures - Nuclear Production
15				Plant and Nuclear Fuel
16		A-13	C5.3	Projected Operation and Maintenance Expenses -
17				Nuclear Power Generation
18		A-13	C5.16	Nuclear Power Generation - Projected PERC O&M
19				Expenditures
20		A-20	J1	Proposed Nuclear Surcharge Projected Test Period –
21				12 Months Ending November 30, 2024
22		A-20	J2	Nuclear Plant Capital Project Detail –
23				Routine and Small Projects
24				

25 **Q10.** Were these exhibits prepared by you or under your direction?

Line
No.

- 1 A10. Yes, they were.
- 2

#### 3 Q11. How do you plan to proceed with your testimony?

A11. I will begin my testimony with the Nuclear Generation capital expenditures;
discussing and supporting the actual capital expenditures for the historical test year
ended December 31, 2021, the projected capital expenditures for the bridge forecast
period and the 12-month projected test period ending November 30, 2024. I have
divided my Nuclear Generation capital expenditure discussion into five sections of
expenditures: Routine and Small Projects, Non-Routine and Large Projects, Nuclear
Fuel, Allowance for Funds Used During Construction (AFUDC), and Plant Activity.

11

I will then discuss and support the actual O&M expenses for the historical test year ended December 31, 2021 and the forecasted O&M expenses for the 12-month projected test period ending November 30, 2024 for Nuclear Generation. I have divided the Nuclear Generation O&M expenses discussion into three sections: rate case adjustments, adjusted historical test period and projected adjustments.

17

I will then discuss and support the Nuclear Surcharge for the 12-month projected
test period ending November 30, 2024 for Nuclear Generation.

20

The Fermi 2 Power Plant is licensed by the Nuclear Regulatory Commission (NRC) to operate through 2045. The capital and O&M expenditures discussed for the historical and projected test periods throughout my testimony reflect appropriate measures to ensure safe and reliable operation of the Fermi 2 Power Plant through 25 2045.

Line <u>No.</u>		<b>J. C. DAVIS</b> U-21297
1		
2	Nucle	ear Generation Capital Expenditures
3	Q12.	Can you provide an outline of your Nuclear Generation capital expenditures
4		discussion?
5	A12.	My testimony will begin with the $2021 - 2024$ Capital Projects Overview and then
6		discuss and support the additional details regarding:
7		Routine and Small Projects
8		Non-Routine and Large Projects
9		• Total Nuclear Fuel
10		AFUDC Forecast
11		• Plant Activity (Removal Costs, Plant in Service and CWIP)
12		
13	<u>2021</u>	- 2024 Capital Projects Overview
14	Q13.	Can you provide an overview of the Nuclear Generation capital expenditures
15		you support?
16	A13.	I refer you to Exhibit A-12, Schedule B5.3, page 1 which depicts the actual capital
17		expenditures for the historical test year ended December 31, 2021, projected capital
18		expenditures for the bridge forecast period and projected capital expenditures for
19		the 12-month projected test period ending November 30, 2024.
20		
21		Total capital expenditures are composed of Routine and Small Projects, Non-
22		Routine and Large Projects, and Total Nuclear Fuel. Nuclear Generation actual
23		capital expenditures for historical test year ended December 31, 2021 totaled \$269.8
24		million as shown on line 11, column (b) of the exhibit. Nuclear Generation forecasts
25		total capital expenditures for the projected bridge forecast period at \$543.9 million

Line <u>No.</u>		<b>J. C. DAVIS</b> U-21297
1		as shown on line 11, column (e) and for the 12-month projected test period ending
2		November 30, 2024 at \$204.2 million as shown on line 11, column (f).
3		
4		I describe and support a portfolio of discrete reasonable and prudent projects and
5		capital fuel expenditures which provides the basis for the historical actual and
6		forecasted Total Capital Expenditures for January 1, 2021 through November 30,
7		2024.
8		
9	Q14.	How do the historical actuals for the 12-month period ending December 31,
10		2021, compare to the Nuclear Generation capital (including nuclear fuel)
11		expenditures authorized for the same period in the U-20836 rate case?
12	A14.	The U-20836 Order authorized Nuclear Generation capital expenditures at \$269.3
13		million for the 12-month period ending December 31, 2021. The actual Nuclear
14		Generation capital expenditures for the same period were \$269.8 million. The total
15		variance is approximately 0.2% of projected total Nuclear Generation capital
16		expenditures for the reference period.
17		
18	Q15.	Before you discuss the discrete projects, can you summarize the principles and
19		conduct of asset maintenance at a nuclear generation unit such as Fermi 2?
20	A15.	Nuclear safety is our overriding priority at Fermi 2 and, indeed, throughout the
21		nuclear industry. Our operational and strategic decisions preserve this priority.
22		
23	Q16.	What do you mean by nuclear safety?

2 nuclear asset with a high degree of rigor. Conservatism is necessary to minimize 3 risk and ensure the safe and reliable use of nuclear material. 4 5 Q17. How does DTE Electric manage nuclear safety risk? 6 A17. DTE Electric manages nuclear safety risk through proper training, procedures and 7 governance, operating the plant consistent with Fermi 2's Nuclear Regulatory 8 Commission (NRC) operating license, operating the plant using the traits of a 9 healthy nuclear safety culture (outlined in the World Association of Nuclear 10 Operators (WANO) Principles PL 2013-1), and maintenance of the asset to support 11 operation through 2045. 12 13 **Q18.** What are the key principles the DTE Electric organization uses for maintaining 14 the nuclear asset? 15 A18. I would summarize our key maintenance principles as: 16 1. Implementation of inspection, surveillance, maintenance and project activities 17 are proactive and condition- or time-based to preclude a failure. Unanticipated 18 equipment failures challenge plant operators and result in unplanned shutdowns 19 or derates of the unit; our strategies are designed to minimize the probabilities 20 of unanticipated equipment failures. 21 2. Work such as capital replacements and modifications are implemented when the 22 plant is in the safest condition to do so. For most of our work at Nuclear 23 Generation, that safest condition is when the Fermi 2 plant is shut down for a 24 refueling outage.

Line No.		<b>J. C. DAVIS</b> U-21297
1		3. Work such as capital replacements and modifications are planned and executed
2		in a reasonable and prudent manner consistent with the other key maintenance
3		and project management principles.
4		
5	Q19.	Why is it safest to perform maintenance on the Fermi 2 plant during a refueling
6		outage?
7	A19.	Refueling outages are the safest time to perform maintenance for the following
8		reasons:
9		1. Nuclear safety - our operating license issued by the NRC requires the plant to be
10		shut down prior to taking many systems out of service for maintenance. These
11		licensing requirements align with minimizing risks to health and safety.
12		2. Personnel safety - many areas of the plant are behind locked doors during
13		operations due to the radiological or atmospheric conditions of the area.
14		Refueling outages offer opportunities to access these otherwise inhospitable
15		areas of the plant for maintenance.
16		
17	Q20.	What is the cadence for the Fermi 2 plant refueling outages?
18	A20.	The Fermi 2 plant now operates on a 24-month cycle, meaning every 24 months the
19		Fermi 2 plant shuts down for a refueling outage. The Fermi 2 refueling outages are
20		numbered sequentially and named as such: our winter/spring 2022 refueling outage,
21		which was Fermi 2's twenty-first refueling outage, was named Refueling Outage 21
22		or RF21 and Fermi 2's twenty-second refueling outage scheduled in the spring of
23		2024 (approximately 24 months after RF21) is named Refueling Outage 22 or RF22.
24		
25	Q21.	What is the typical planning cadence for a Fermi 2 plant refueling outage?

Line <u>No.</u>		<b>J. C. DAVIS</b> U-21297
1	A21.	Refueling outages are highly complex and require an integrated work plan to execute
2		thousands of activities in a relatively short duration.
3		
4		Planning for a refueling outage is generally a two-year effort with many intermediate
5		milestones guiding the planning effort; completion of these milestones requires
6		consideration of the existing and projected material condition of the Fermi 2 Power
7		Plant as well as any practical constraints for safe execution of the projected work.
8		The two most relevant of these milestones for capital expenditures are (1) two years
9		prior to the refueling outage (T-24 months), Nuclear Generation confirms the Non-
10		Routine and Large Projects for implementation in the outage and (2) at one year
11		prior to the refueling outage (T-12 months), Nuclear Generation establishes for the
12		Routine and Small Projects to be completed in the outage.
13		
14	Q22.	How does the highly complex and integrated characteristic of refueling outage
15		work impact project planning and execution?
16	A22.	Projects implemented during refueling outages are not stand-alone, independent
17		projects as one may typically think of projects.
18		
19		For example, plant workers such as plant operators, radiation protection, building
20		trades and supervision are not dedicated to individual projects but must be shared
21		across different projects and maintenance because qualified nuclear professionals
22		are finite, nuclear standards are exacting, and gaining clearance to work at a U.S.
23		nuclear plant is non-trivial; suppliers performing work must be chosen to globally
24		improve outage execution - selecting suppliers as if projects were independent

Line <u>No.</u>		J. C. DAVIS U-21297
1		would lead to more expensive work, unnecessary duplication of oversight and
2		potential conflicts between suppliers.
3		
4		As a second example, projects and maintenance activities may only occur in a
5		specific schedule sequence which means performance of one project may impact
6		performance of another project or projects.
7		
8		As I said, this coordination of work and resources is important to finalizing refueling
9		outage plans and takes place in the cycle leading up to the refueling outage.
10		
11	Q23.	How are suppliers chosen to globally improve work execution?
12	A23.	Suppliers of nuclear equipment, components and services are relatively limited and
13		serve a relatively small group of U.S. nuclear power stations. After Palisades
14		Nuclear Plant closed in 2022, 92 U.S. commercial nuclear reactors remain operating
15		- and consolidation of suppliers is such that in many instances only one or two
16		suppliers are qualified to provide certain nuclear components, equipment or services
17		to nuclear power plants. Fermi 2 is further unique in that the plant is a General
18		Electric Boiling Water Reactor Type 4 design (GE BWR/IV) with a Mark I
19		containment structure and English Electric turbine/generator system. To be
20		reasonable and prudent, selecting suppliers generally requires DTE Electric to weigh
21		more than just the competitively bid costs: DTE Electric must consider supplier
22		qualifications, safety record, original equipment manufacturer (OEM) status,
23		incumbency, market share, industry operating experience and industry feedback,
24		locality, ownership, union status and integration with the local building trades (if
25		applicable), proposed schedule and costs, terms and conditions, likelihood of

JCD-10

Line

<u>No.</u>

1

2

outcomes, amongst other factors. If a new participant enters a market, then supporting overall market competition can become a factor as well.

3

4 DTE Electric secures long-term supplier agreements for Fermi 2 nuclear fuel, 5 reactor services, turbine services, major maintenance services, heavy construction 6 services, radiation protection services and engineering design services through 7 competitive supplier sourcing and negotiation. Individual projects can then source, 8 as needed, suppliers using these long-term agreements which facilitates each major 9 supplier's resources being integrated into the overall work plan. DTE Electric 10 sources other components, equipment and services in a reasonable and prudent 11 manner consistent with the factors I outlined above.

12

#### 13 Routine and Small Projects Capital Expenditures

# Q24. Can you further explain the Routine and Small Projects summarized on line 2 of Exhibit A-12, Schedule B5.3, page 1?

16 A24. Routine and Small Projects are those capital expenditures associated with 17 maintaining the various assets that support the safe operation of Fermi 2 and 18 includes work such as pump, motor, valve and reactor control component 19 replacements and can typically be expressed in number of units replaced. Routine 20 and Small Projects are reasonable and prudent because these types of projects 21 address commonly activated and used equipment that are the core of our proactive 22 maintenance regime to maintain nuclear safety. Proactive replacement of these 23 Fermi 2 components is essential to prioritizing nuclear safety by minimizing the 24 potential for unanticipated or unrecoverable failures during plant operation.

25

Line <u>No.</u>		<b>J. C. DAVIS</b> U-21297
1		Pages 2-3 of Exhibit A-12, Schedule B5.3 provide a listing of the Routine and Small
2		Projects that support page 1, line 2.
3		
4	Q25.	Can you explain the Routine and Small Projects detailed in Exhibit A-12,
5		Schedule B5.3, pages 2-3?
6	A25.	Exhibit A-12, Schedule B5.3, pages 2-3 show the by-project capital expenditures
7		for Routine and Small Projects for the historical test year and the projected
8		expenditures for the 22-month bridge forecast period ending November 30, 2023
9		and the 12-month projected test period ending November 30, 2024 which total \$53.9
10		million, \$152.2 million and \$84.5 million respectively. Additional details for select
11		routine and small projects are provided in Exhibit A-20, Schedule J2.
12		
13		The expenditures and project make-up are generally consistent each operating cycle
14		and peak during refueling outage periods because of the regulatory and safety
15		requirements governing Routine and Small Projects. I will highlight specific
16		Routine and Small Projects to help convey the type of projects that comprise Routine
17		and Small Projects. I will also discuss the Routine and Small Projects that the
18		Commission has expressed incremental interest in during DTE Electric rate case U-
19		20836.
20		
21	Q26.	Which Routine and Small Projects did the Commission express additional
22		interest towards in U-20836?
23	A26.	The Commission expressed incremental interest in three Routine and Small
24		Projects: (1) Security System Computer, (2) Plant Radio System and (3) Plant
25		Wireless. I will discuss these three Routine and Small Projects next.

# JCD-12

#### 2 **Q27.** Can you discuss the expenditures and rationale for the Security System 3 Computer replacement project shown on Exhibit A-12, Schedule B5.3, page 2, 4 line 17?

5 A27. The Security System Computer replacement project capital expenditures for the 6 historical test year, projected bridge forecast period and projected test period are 7 \$1.2 million, \$21.2 million and \$1.5 million respectively, do not extend beyond the 8 projected test period, address aging and obsolescence of the existing security system 9 computer, and support the necessary replacement of the Fermi 2 Security System 10 Computer which includes specialized computer servers, video cameras, other access 11 control and detection devices, and communication cabling. This major plant security 12 system is an aspect of the regulatory-required Fermi 2 Security Protection Plan per 13 Code of Federal Regulation 10 CFR 73.55 which requires a physical security plan 14 that must "ensure that the capabilities to detect, assess, interdict, and neutralize 15 threats up to and including the design basis threat of radiological sabotage as stated in 10 CFR 73.1, are maintained at all times" and "provide defense-in-depth through 16 17 the integration of systems, technologies, programs, equipment, supporting 18 processes, and implementing procedures as needed to ensure the effectiveness of the 19 physical protection program."

- 20

#### 21 Q28. Why is replacement of the security system computer necessary within the 22 projected test period?

23 A28. Components of the existing security system computer have exhibited decreased 24 performance as service time has increased. Degradation of security equipment 25 results in multiple alarms that distract the security force from core activities, requires

Line No.

> 1 compensatory measures which require unscheduled overtime, requires emergent 2 maintenance, and increases the risk of gaps in meeting the regulatory 3 requirements. In 2022, one of the intrusion detection systems accumulated three 4 times the annual out of service time than it did in 2021, indicating a need to replace 5 the system. Repair and replacement of existing components has become 6 increasingly difficult as equipment becomes obsolete; for example, vendor 7 supported software updates ceased for the security system computer's video 8 monitoring software, video server operating system, and the server and workstation 9 operating system 2015, 2016 and 2020 respectively. Lack of vendor support for 10 these operating systems or video monitoring systems could lead to extended loss of 11 security video feeds which would require additional security personnel to 12 compensate for the loss of video surveillance.

13

14 A security computer system used in the security of a nuclear power plant can be 15 reasonably expected to be in service for approximately 10 - 15 years based on 16 anticipated aging and obsolescence factors. Aspects of the Fermi 2 security system 17 computer such as the communications cabling have been in service for more than 18 thirty years; while the security system computer servers, workstations and access 19 controls hardware is comparatively newer - this hardware still relies on late-2000s 20 vintage technology. NRC cyber security regulations and the deeply integrated nature 21 of the security system computer makes replacement components increasingly 22 impractical to procure.

23

24 Preemptive replacement of the security system computer and its constituent 25 components is a reasonable and prudent action, consistent with our nuclear safety

1		priorities to support DTE Electric continuing to meet its regulatory commitments
2		into the 2030s when DTE Electric anticipates the next routine replacement of the
3		security system computer to occur. Several portions of this project also bring
4		equipment and strategy up to nuclear industry standards. Additionally, these
5		replacements will allow for more efficient equipment maintenance.
6		The integrated project also includes addition of equipment, for example, additional
7		cameras, and changes to the location of some equipment in order to support
8		satisfactory outcomes from NRC-graded Force-on-Force exercises as well as a
9		formal assessment of the Security Strategy.
10		
11		
12	Q29.	What is the role of the security computer system within the nuclear safety
13		paradigm you discussed earlier in your testimony?
14	A29.	The security computer system itself is an aspect of the Fermi 2 Physical Security
15		Plan (the exact details of physical security plans are safeguarded and protected per
16		regulation) - having and maintaining Fermi 2's security equipment in accordance
17		with the approved physical security plan is a regulatory requirement and a condition
18		to maintaining the Fermi 2 operating license. Because the consequences of hostile
19		actors acting against a U.S. commercial nuclear plant are significant, each U.S.
20		commercial nuclear site's physical security plan is routinely inspected and tested by
21		the NRC to ensure compliance. DTE Electric has an obligation to ensure that all
22		aspects of the Fermi 2 physical security plan work and will continue to work in the
22 23		aspects of the Fermi 2 physical security plan work and will continue to work in the future – hence a preemptive replacement regimen is necessary to ensure components
22 23 24		aspects of the Fermi 2 physical security plan work and will continue to work in the future – hence a preemptive replacement regimen is necessary to ensure components of the security computer system do not unexpectedly or unrecoverably fail.

1	As DTE Electric replaces the existing security computer system, Fermi 2 must
2	remain in compliance with regulations such that: (1) the functions and capabilities
3	of the existing security computer system must be maintained while the new system
4	is being installed, (2) design, configuration control and work to replace the existing
5	security computer systems must be performed as to maintain operability of other
6	Fermi 2 plant systems including taking special care when excavating to replace
7	cabling and other components, (3) the new security computer system must meet
8	NRC cyber security requirements, (4) the new system must be designed and tested
9	for continuous operations with minimal maintenance time. Total project
10	expenditures are commensurate with these regulatory requirements.

#### 12 Q30. Was the Security System Computer project competitively sourced?

- A30. Yes. Consistent with the commercial principles I discussed earlier, the Security
   System Computer project uses competitively-sourced suppliers. While commercial
   processes and agreements are sensitive information, DTE Electric provides relevant
   sourcing documents, subject to non-disclosure orders, within the natural order of
   this proceeding; other supplier and project information can be found in this
   proceeding's Part III, Attachment 9 supplement filing.
- 19

Total project costs reasonably and prudently reflect actual and projected costs based on the commercial solicitations and agreements. As I discussed earlier, commercial solicitation processes such as competitive sourcing is a principle of prioritizing nuclear safety to support safe, reliable and efficient project execution and postimplementation equipment operations.

25

#### 1 Q31. Can you discuss the expenditures and rationale for the Plant Radio System 2 replacement project shown on Exhibit A-12, Schedule B5.3, page 2, line 8? 3 A31. The Plant Radio System capital expenditures for the historical test year, projected 4 bridge forecast period and the projected test period are \$2.3 million, \$8.7 million 5 and \$1.0 million respectively, do not extend beyond the projected test period, 6 address security and operations vulnerabilities of the existing plant radio system, 7 and support the necessary replacement of the Fermi 2 plant radio system which 8 includes computers, radio repeaters, radio antenna, uninterruptible power supplies 9 and communications cabling. This major system is an aspect of the regulatory-10 required Fermi 2 Physical Security Plan and the regulatory-required Fermi 2 11 Radiological Emergency Response Plan and has the purpose to be the primary 12 means of communication for plant personnel including site security and fire brigade 13 during operations and potential accident scenarios; loss of the plant radio system 14 would degrade plant operators' ability to safely operate the Fermi 2 Power Plant.

15

# Q32. Why is replacement of the plant radio system necessary within the projected test period?

18 A32. Security and operations vulnerabilities. Replacement of the plant radio system began 19 in 2017 with the replacement of plant radio equipment in the Fermi 2 Main Control 20 Room (MCR); field radio communications to the MCR were becoming increasingly 21 inaudible within the MCR which was unduly burdening plant operators during plant 22 operations. Additionally, radio communications within the power plant uses an antenna system installed in the early 1980s, experiences a 90% signal loss between 23 24 the base station and the distributed antennas and is capable of transmitting only the 25 UHS frequency band – replacement of the plant radio system distributed antenna

1		system, communications cabling and uninterruptible power supplies (which is the
2		scope of work during the bridge and projected test periods in this case) will improve
3		plant radio signal fidelity throughout the plant and add two additional radio
4		frequencies bands (VHS and 800 MHZ) within the power plant.
5		
6		Improving plant radio signal fidelity within the plant supports improved operations
7		communications, especially for emergency responders such as fire brigade in all
8		areas of the plant.
9		
10		Adding the two additional radio frequency bands also allows DTE Electric to
11		evaluate changes to the Fermi 2 Physical Security Plan, further improve Fermi 2's
12		security posture and enhance security's communication capabilities with outside
13		emergency responders such as the Michigan State Police
15		emergency responders such as the Whemgan State Fonce.
14		energency responders such as the Wienigan State Fonce.
14 15	Q33.	What is the role of the plant radio system within the nuclear safety paradigm
13 14 15 16	Q33.	What is the role of the plant radio system within the nuclear safety paradigm you discussed earlier in your testimony?
14 15 16 17	<b>Q33.</b> A33.	What is the role of the plant radio system within the nuclear safety paradigm you discussed earlier in your testimony? The plant radio system is an aspect of the Fermi 2 Radiological Emergency
14 15 16 17 18	<b>Q33.</b> A33.	<ul> <li>What is the role of the plant radio system within the nuclear safety paradigm you discussed earlier in your testimony?</li> <li>The plant radio system is an aspect of the Fermi 2 Radiological Emergency Response Plan – having and maintaining Fermi 2's plant radio equipment in</li> </ul>
14 15 16 17 18 19	<b>Q33.</b> A33.	What is the role of the plant radio system within the nuclear safety paradigm you discussed earlier in your testimony? The plant radio system is an aspect of the Fermi 2 Radiological Emergency Response Plan – having and maintaining Fermi 2's plant radio equipment in accordance with the approved emergency response plan is a regulatory requirement
14 15 16 17 18 19 20	<b>Q33.</b> A33.	What is the role of the plant radio system within the nuclear safety paradigm you discussed earlier in your testimony? The plant radio system is an aspect of the Fermi 2 Radiological Emergency Response Plan – having and maintaining Fermi 2's plant radio equipment in accordance with the approved emergency response plan is a regulatory requirement and a condition to maintaining the Fermi 2 operating license. Because the
14 15 16 17 18 19 20 21	<b>Q33.</b> A33.	What is the role of the plant radio system within the nuclear safety paradigm you discussed earlier in your testimony? The plant radio system is an aspect of the Fermi 2 Radiological Emergency Response Plan – having and maintaining Fermi 2's plant radio equipment in accordance with the approved emergency response plan is a regulatory requirement and a condition to maintaining the Fermi 2 operating license. Because the consequences of an ineffective radiological emergency response are significant,
<ol> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> </ol>	<b>Q33.</b> A33.	What is the role of the plant radio system within the nuclear safety paradigm you discussed earlier in your testimony? The plant radio system is an aspect of the Fermi 2 Radiological Emergency Response Plan – having and maintaining Fermi 2's plant radio equipment in accordance with the approved emergency response plan is a regulatory requirement and a condition to maintaining the Fermi 2 operating license. Because the consequences of an ineffective radiological emergency response plan is routinely inspected
<ol> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>23</li> </ol>	<b>Q33.</b> A33.	What is the role of the plant radio system within the nuclear safety paradigm you discussed earlier in your testimony? The plant radio system is an aspect of the Fermi 2 Radiological Emergency Response Plan – having and maintaining Fermi 2's plant radio equipment in accordance with the approved emergency response plan is a regulatory requirement and a condition to maintaining the Fermi 2 operating license. Because the consequences of an ineffective radiological emergency response plan is routinely inspected and tested by the NRC and the Federal Emergency Management Agency (FEMA)
<ol> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>23</li> <li>24</li> </ol>	<b>Q33.</b> A33.	What is the role of the plant radio system within the nuclear safety paradigm you discussed earlier in your testimony? The plant radio system is an aspect of the Fermi 2 Radiological Emergency Response Plan – having and maintaining Fermi 2's plant radio equipment in accordance with the approved emergency response plan is a regulatory requirement and a condition to maintaining the Fermi 2 operating license. Because the consequences of an ineffective radiological emergency response plan is routinely inspected and tested by the NRC and the Federal Emergency Management Agency (FEMA) to ensure compliance. DTE Electric has an obligation to ensure that the components

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3

work in the future – hence a preemptive replacement regimen is reasonable and prudent.

- The plant radio system is the primary communication means for plant operators and security officers responding to emergency conditions – unexpected or unrestorable failure or interruption of this equipment would be an unacceptable risk to first responders to any Fermi 2 plant emergency; it is imperative that the plant radio system maintains its capabilities throughout the plant and through all postulated operating scenarios.
- 10

11 As Fermi 2 replaces the existing plant radio system, the Company must remain in 12 compliance with regulations such that: (1) the functions and capabilities of the 13 existing plant radio system must be maintained while the new system is being 14 installed, (2) design, configuration control and work to replace the existing plant 15 radio system must be performed as to maintain operability of other Fermi 2 plant 16 systems, (3) the new plant radio system must meet NRC cyber security 17 requirements, (4) the new system must be designed and tested for continuous 18 operations with minimal maintenance time. This requires installing 16 new antennae 19 and approximately 5800 feet of new conduit and cable. Total project expenditures 20 are commensurate with these regulatory requirements.

21

# Q34. Can you discuss the expenditures and rationale for the Plant Wireless project shown on Exhibit A-12, Schedule B5.3, page 3, line 46?

A34. The Plant Wireless project capital expenditures for the historical test year, projected
bridge forecast period and the projected test period are \$0.0 million, \$6.0 million
1 and \$0.5 million respectively, do not extend beyond the projected test period, 2 address operational vulnerabilities and support the replacement and expansion of the 3 existing Fermi 2 plant wireless system which includes modems, network switches, 4 and wireless antennae. The purpose of the plant wireless system is to provide 5 wireless data communications capacity to plant personnel during normal operations; 6 not replacing and expanding the plant wireless system would challenge operations to effectively operate the plant. In addition, the Plant Wireless project is resource-7 8 optimized with the Plant Radio System replacement project by sharing the conduit 9 and cable trays.

10

### Q35. What is the role of the plant wireless system within the nuclear safety paradigm you discussed earlier in your testimony?

13 A35. Installation of a wireless communication backbone throughout the nuclear power 14 block directly impacts the ability to progress with other cost-savings and radiological dose-savings initiatives including Electronic Work Orders, Electronic 15 16 Operator Rounds, remote dose monitoring and remote equipment monitoring. NRC 17 regulations require management measures which include configuration 18 management, maintenance, training and certification, procedures, records 19 management, and other quality assurance methods, generally on a continuing basis, 20 that are applied to items relied on for safety, to ensure the items are available and 21 reliable to perform their functions when needed. Plant wireless system provides the 22 networking infrastructure and capacity necessary for Fermi 2 to modernize and maintain these management measures. Plant wireless networks are used in the 23 nuclear industry to provide efficiency in recording and automatically storing 24 25 regulatory-required documentation and for additional monitoring of equipment 1

2

3

important to nuclear safety and plant reliability without incurring the large costs of permanent imbedded cabling.

4 Existing management measures require controlled paper copies of work orders, 5 plant drawings, engineering design documents, purchasing agreements, time sheets 6 and procedures in the field – not that different from when the Fermi 2 first started 7 commercial operations in 1988. While these paper-document management measures 8 continue to support safe and reliable operations, modern industry-best practices have 9 evolved to use paperless work orders and procedures, automated document control 10 and records management, and electronic time keeping systems to reduce human 11 error precursors and to maintain positive configuration control of the plant.

12

13 As DTE Electric replaces and expands the existing plant wireless system, the 14 Company must remain in compliance with regulations such that: (1) design, 15 configuration control and work to replace and expand the existing plant wireless 16 system must be performed as to maintain operability of other Fermi 2 plant systems, 17 (2) wireless network signals from the plant wireless system must strike a difficult 18 engineering balance between strong signal strength and bandwidth against 19 requirements that the signals not interfere with the function of other plant equipment 20 and (3) the new plant wireless system must meet NRC cyber security requirements. 21 Total project expenditures are commensurate with these regulatory requirements.

- 22
- 23 Q36. What do you mean by "aging and obsolescence?"

1 A36. Aging in the context of nuclear plant operations refers to the general process in 2 which characteristics of equipment or components gradually degrade with time or 3 use. 4 5 Component obsolescence in the context of nuclear plant operations refers to 6 equipment or components that are no longer manufactured or qualified by their 7 original manufacturers. 8 9 Q37. Why is obsolescence a particular concern for DTE Electric at the Fermi 2 10 **Power Plant?** 11 A37. I have discussed aging and obsolescence a few times already because aging and 12 obsolescence concerns are not just a focus for DTE Electric, but a focus for the entire 13 U.S. nuclear industry. Configuration management at a nuclear power plant specifies 14 allowed components by manufacturer and model number. Once manufacturers cease 15 operations, change ownership or cease production of a particular model, nuclear 16 operators must identify potential replacements. This process of identifying potential 17 replacements is rigorous as all aspects of the potential replacement's fit, form and 18 function must be evaluated by qualified engineers. Potential replacements may also 19 require physical modification to the plant to be usable – Security System Computer 20 is one such project that requires modifications to the Fermi 2 plant to address aging 21 and obsolescence. 22 23 Unexpected or unrecoverable failures of obsolete components are a vulnerability to 24 safe and reliable plant operations. Of course, as components age, the vulnerability 25 of unrecoverable failure increases. Unexpected or unrecoverable failures of obsolete

components could result in the extended compensatory measures that burden
 operations, security or other plant personnel or shutdown of the plant until potential
 replacements are identified and actions are taken to make the replacement usable
 within the plant.
 **Q38.** What actions must a nuclear operator such as DTE Electric take to physically
 modify the plant?

8 A38. When new or replacement components or equipment require a plant modification, 9 in addition to the physical field work of the modification there are several 10 management actions required: (1) plant drawings and component databases must be 11 updated, (2) plant calculations must be revised to ensure sufficient structural loading 12 or electrical loading margins exist, (3) physical security and emergency response 13 plans must be evaluated and possibly revised, (4) operating license and safety 14 analysis reporting must be evaluated and possibly revised, and (5) training, 15 operations and maintenance programs must be evaluated and possibly revised.

16

17 The resources, time and costs of these regulatory-required management measures18 are non-trivial.

19

Q39. Can you discuss the expenditures and rationale for the Undervessel
 Replacements project shown on Exhibit A-12, Schedule B5.3, page 2, line 6?

A39. The Undervessel Replacements capital expenditures for the historical test year,
 projected bridge forecast period and projected test period are \$2.5 million, \$8.9
 million, and \$7.4 million respectively, do extend beyond the projected test period
 and through the balance-of-life of the Fermi 2 Power Plant, address component

1 aging, and support the necessary replacement of undervessel components which 2 include control rod drives and nuclear instrumentation such as local power range 3 monitors (LPRMs). The purpose of undervessel components goes to the heart of 4 safely operating a nuclear reactor and directly affects control and monitoring of 5 power levels throughout the reactor core (undervessel components are so named 6 because the components are driven by equipment located underneath the reactor 7 pressure vessel); unplanned or unrecoverable loss of these components would 8 challenge plant operator's ability to safely operate the Fermi 2 plant.

9

Q40. Can you discuss the expenditures and rationale for the Control Rod Blade
 Replacements project shown on Exhibit A-12, Schedule B5.3, page 2, line 12?

- 12 A40. The Control Rod Blade (CRB) Replacement project capital expenditures for the 13 historical test year, projected bridge forecast period and projected test period are 14 \$1.9 million, \$1.0 million, and \$1.4 million respectively, do extend beyond the 15 projected test period and through the balance-of-life of the Fermi 2 Power Plant, 16 closely relates to the Undervessel Replacements projects, address CRB component 17 aging, and support the necessary replacement of the CRBs (DTE Electric replaced 18 19 CRBs in RF21 and projects replacement of 22 CRBs in RF22). The purpose of 19 Fermi 2's 185 CRBs is to control power levels within the reactor core and to 20 ultimately safely accomplish shut down of the reactor when appropriate; unplanned 21 or unrecoverable loss of the CRBs would challenge plant operator's ability to safely 22 operate the Fermi 2 plant.
- 23

Q41. Can you discuss the expenditures and rationale for the Control Rod Drive
 Mechanisms project shown on Exhibit A-12, Schedule B5.3, page 2, line 2?

1 A41. The Control Rod Drive Mechanism (CRDM) replacement project capital 2 expenditures for the historical test year, projected bridge forecast period and 3 projected test period are \$4.8 million, \$5.6 million, and \$0.4 million respectively, 4 do extend beyond the projected test period and through the balance-of-life of the 5 Fermi 2 Power Plant, closely relates to the Undervessel Replacements projects, 6 address CRDM component aging, and support the necessary replacement of the 7 CRDMs (DTE Electric replaced 15 CRDMs in RF21 and projects replacement of 8 15 CRDMs in RF22). The purpose of Fermi 2's 185 CRDMs is to control power 9 levels within the reactor core and to ultimately safely accomplish shut down of the 10 reactor upon receiving either manual or automatic signals; unplanned or 11 unrecoverable loss of the CRDMs would challenge plant operator's ability to safely 12 operate the Fermi 2 plant.

13

### 14 Q42. Why is Fermi projecting to replace 22 CRBs in RF22 and only 15 CDRMs in 15 RF22?

16 A42. Although CRBs and CRDMs are part of the same control rod drive system, the aging 17 mechanism is very different between CRDMs and CRBs. CRDMs (hydraulic piston 18 assemblies located underneath the reactor pressure vessel) are subject to harsh 19 environmental conditions such as extreme heat, moisture and radiation; after time, 20 the components of the CRDM will naturally stress, fatigue and wear and must be 21 replaced. CRBs (crucible-shaped, metal-tube components that contain a neutron-22 absorbing material located inside the reactor core adjacent to fuel assemblies) are 23 subject to the extreme environment of the reactor itself; after time, the neutron-24 absorbing material is consumed preventing it from fully performing its function to

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1		shutdown the reactor or the CRB structural material will stress, fatigue and wear and
2		may become damaged during operation which could directly impact fuel integrity.
3		
4		Each component of the control rod drive system must be evaluated and replaced on
5		its own schedule. For CRBs, DTE Electric determines this schedule based on
6		analysis of the operational history of the individual CRBs, calculates remaining
7		useful core life, and performs confirmatory testing to ensure the CRBs perform as
8		expected. For CRDMs, DTE Electric levelizes the replacements of the CRDMs over
9		their approximately 12-cycle in-service life.
10		
11	Q43.	What is the status of the commercial agreements for the Undervessel
12		Replacements, CRBs and CRDMs?
13	A43.	DTE Electric has negotiated long-term commercial agreements (using the
14		commercial principles I discussed earlier) for the OEM suppliers to provide these
15		vital nuclear components and services through at least 2027. These long-term
16		agreements provide DTE Electric with high assurance of adequate supply of
17		nuclear-quality plant components at predictable quality, compatibility and cost -
18		which is certainly reasonable and prudent.
19		
20	Q44.	What are the expenditures and rationale for the Roof Replacements project
21		shown on Exhibit A-12, Schedule B5.3, page 3, line 48?
22	A44.	The Roof Replacements project capital expenditures for the historical test year,
23		projected bridge forecast period and projected test period are \$0.0 million, \$5.0
24		million, and \$0.0 million respectively, do extend beyond the projected test period
25		and through the balance-of-life of the Fermi 2 Power Plant, address Fermi 2 building

roof aging, and support the necessary replacements of approximately 110,000
 square feet of degraded roofs located at the Fermi 2 Office Building Annex (OBA),
 Office Service Building (OSB), Radiological Waste Building, Auxiliary Boiler
 House, Warehouse A, Warehouse C, General Service Water Building, and Buildings
 27, 40 and 96.

6

#### 7 Q45. Why is replacement of these roofs necessary within the projected test period?

8 A45. Aging. The roofs in question leak. The Fermi 2 OBA and OSB house nuclear 9 operations staff, work control, outage management staff and maintenance staff as 10 well as the Fermi 2 maintenance shops (Mechanical, Electrical and Instrument & 11 Controls (I&C) and machine shop). Warehouse A is the warehouse within the Fermi 12 2 Protected Area used for staging parts and materials for upcoming work. 13 Warehouse C is the Fermi 2 hazardous materials storage warehouse. Buildings 27, 14 40 and 96 are used for shop work such as fabricating insulation blankets. The 15 Auxiliary Boiler House contains Fermi 2's two auxiliary boilers which provide low 16 pressure steam for plant heating and to the radwaste evaporators. The Radiological Waste Building is where Fermi 2 personnel warehouse, package and ready for 17 18 disposal low-level radiological waste. Active water leaks in any of these buildings 19 present an unacceptable risk to plant personnel, materials or equipment.

20

### Q46. What is the role of the Roof Replacements project within the nuclear safety paradigm you discussed earlier in your testimony?

A46. All workers – at a nuclear power plant or otherwise, should be able to work in an
environment safe from industrial hazards such as leaking roofs.

25

1		Our U.S. nuclear industry refers to workers at nuclear power plants as "nuclear
2		professionals." Our industry places considerable expectations on nuclear
3		professionals and appropriately so given the obligation to safely operate nuclear
4		power plants. One of these expectations is that nuclear professionals are to practice
5		good housekeeping and control of work areas to minimize the potential for injuries,
6		likelihood of human error, the spread of contamination and the generation of nuclear
7		waste; tolerating leaking roofs, which have the potential to undermine any of the
8		aspects of the expectation I just outlined risks undermining a criterion of nuclear
9		professionalism – which would not be reasonable and would not be prudent.
10		
11	Q47.	Can you discuss the expenditures and rationale for the Visual Annunciator
12		System (VAS) Replacement project shown on Exhibit A-12, Schedule B5.3,
13		page 2, line 4?
13 14	A47.	<pre>page 2, line 4? The Visual Annunciator System (VAS) Replacement project capital expenditures</pre>
13 14 15	A47.	page 2, line 4? The Visual Annunciator System (VAS) Replacement project capital expenditures for the historical test year, projected bridge forecast period and projected test period
13 14 15 16	A47.	page 2, line 4? The Visual Annunciator System (VAS) Replacement project capital expenditures for the historical test year, projected bridge forecast period and projected test period are \$3.2 million, \$7.5 million, and \$0.0 million respectively, do not extend beyond
13 14 15 16 17	A47.	page 2, line 4? The Visual Annunciator System (VAS) Replacement project capital expenditures for the historical test year, projected bridge forecast period and projected test period are \$3.2 million, \$7.5 million, and \$0.0 million respectively, do not extend beyond the test period, addressed component aging and obsolescence and supported the
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> </ol>	A47.	page 2, line 4? The Visual Annunciator System (VAS) Replacement project capital expenditures for the historical test year, projected bridge forecast period and projected test period are \$3.2 million, \$7.5 million, and \$0.0 million respectively, do not extend beyond the test period, addressed component aging and obsolescence and supported the necessary replacement of the Fermi 2 VAS (completed in RF21). The purpose of
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> </ol>	A47.	page 2, line 4? The Visual Annunciator System (VAS) Replacement project capital expenditures for the historical test year, projected bridge forecast period and projected test period are \$3.2 million, \$7.5 million, and \$0.0 million respectively, do not extend beyond the test period, addressed component aging and obsolescence and supported the necessary replacement of the Fermi 2 VAS (completed in RF21). The purpose of this major plant computer system that includes computer processors, circuit cards,
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> </ol>	A47.	page 2, line 4? The Visual Annunciator System (VAS) Replacement project capital expenditures for the historical test year, projected bridge forecast period and projected test period are \$3.2 million, \$7.5 million, and \$0.0 million respectively, do not extend beyond the test period, addressed component aging and obsolescence and supported the necessary replacement of the Fermi 2 VAS (completed in RF21). The purpose of this major plant computer system that includes computer processors, circuit cards, labeled tiles (visual displays of reactor and plant functions in the Fermi 2 control
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> </ol>	A47.	page 2, line 4? The Visual Annunciator System (VAS) Replacement project capital expenditures for the historical test year, projected bridge forecast period and projected test period are \$3.2 million, \$7.5 million, and \$0.0 million respectively, do not extend beyond the test period, addressed component aging and obsolescence and supported the necessary replacement of the Fermi 2 VAS (completed in RF21). The purpose of this major plant computer system that includes computer processors, circuit cards, labeled tiles (visual displays of reactor and plant functions in the Fermi 2 control room), pushbuttons and auditory devices is to alert plant operators when a process
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> </ol>	A47.	page 2, line 4? The Visual Annunciator System (VAS) Replacement project capital expenditures for the historical test year, projected bridge forecast period and projected test period are \$3.2 million, \$7.5 million, and \$0.0 million respectively, do not extend beyond the test period, addressed component aging and obsolescence and supported the necessary replacement of the Fermi 2 VAS (completed in RF21). The purpose of this major plant computer system that includes computer processors, circuit cards, labeled tiles (visual displays of reactor and plant functions in the Fermi 2 control room), pushbuttons and auditory devices is to alert plant operators when a process parameter or system condition is not normal; unplanned or unrecoverable loss of the
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>23</li> </ol>	A47.	page 2, line 4? The Visual Annunciator System (VAS) Replacement project capital expenditures for the historical test year, projected bridge forecast period and projected test period are \$3.2 million, \$7.5 million, and \$0.0 million respectively, do not extend beyond the test period, addressed component aging and obsolescence and supported the necessary replacement of the Fermi 2 VAS (completed in RF21). The purpose of this major plant computer system that includes computer processors, circuit cards, labeled tiles (visual displays of reactor and plant functions in the Fermi 2 control room), pushbuttons and auditory devices is to alert plant operators when a process parameter or system condition is not normal; unplanned or unrecoverable loss of the VAS or VAS components would challenge plant operator's ability to safely operate

25

1	Q48.	How old was the Fermi 2 VAS when replacement was completed in RF21?
2	A48.	The previous VAS system had been in service for approximately twenty years as it
3		was installed in 2002. The VAS computer hardware and software used technology
4		from circa-1997.
5		
6		DTE Electric replaced the VAS in coordination with the Fermi 2 Integrated Plant
7		Computer System (IPCS) Replacement project which was replaced in RF20 to
8		address aging and obsolescence. Because the IPCS and VAS are highly integrated
9		systems using similar components of similar vintage experiencing similar aging and
10		obsolescence, DTE Electric replaced these two critical computer-based systems to
11		support safe and reliable operations in the Fermi 2 period of extended operations
12		through 2045.
13		
14	Non-	Routine and Large Projects Capital Expenditures
15	Q49.	Can you discuss the Non-Routine and Large Projects summarized on line 3 of
16		Exhibit A-12, Schedule B5.3, page 1?
17	A49.	Non-Routine and Large Projects are projects that are necessary to properly maintain
18		the Fermi 2 asset and are incremental to normal routine capital expenditures.
19		
20		Refer to Page 4 of Exhibit A-12, Schedule B5.3 for a listing of the projects that
21		support page 1, line 3.
22		
23	Q50.	Can you explain the Non-Routine and Large Projects detailed in Exhibit A-12,
24		Schedule B5.3, page 4?

1	A50.	Yes. This exhibit shows the by-project capital expenditures for Non-Routine and
2		Large Projects, as noted by line 3 of Exhibit A-12, Schedule B5.3, page 1. These
3		projects for the historical test year, the projected expenditures for the 22-month
4		bridge forecast period ending November 30, 2023 and the 12-month projected test
5		period ending November 30, 2024 total \$95.8 million, \$271.1 million and \$119.5
6		million respectively. A discussion of certain Non-Routine and Large Projects
7		follows.
8		
9	Q51.	Can you explain the expenditures and rationale for the Main Unit Generator
10		projects shown on line 2 and line 7 of Exhibit A-12, Schedule B5.3, page 4?
11	A51.	The main unit generator projects are a series of replacements necessary to address
12		both an Original Equipment Manufacturer (OEM) design vulnerability and improve
13		overall reliability. These projects also support electrical grid reliability.
14		Replacement of this model of generator is the identical approach other nuclear
15		generation owners have taken over the years to mitigate operational risk. To support
16		reliable operation of Fermi 2 through 2045, major refurbishments and replacement
17		of the existing generator asset is reasonable and prudent. The replacement main unit
18		generator stator, as of January 2023, is at the manufacturing facility in New York.
19		Work is ongoing to ready the replacement main unit generator stator. DTE Electric
20		will continue to make reasonable and prudent decisions to ensure the main unit
21		generator project, once complete, will support safe and reliable operations through
22		Fermi 2's operating license termination date in 2045
23		
24		The Main Unit Generator rotor replacement project as depicted on line 7 replaced

25 the existing main unit generator rotor with a refurbished spare rotor during RF21.

1 This replacement was performed to mitigate operational vulnerabilities associated 2 with the existing main unit generator. This replacement occurred during RF21 and 3 has capital expenditures for the historical test year, projected bridge forecast period 4 and projected test period of \$8.0 million, \$16.0 million and \$0.0 million 5 respectively.

6

The Main Unit Generator Replacement project as depicted on line 2 is to replace the
generator stator and rotor with a matched stator and rotor. This replacement is
projected to occur during RF22 and has capital expenditures for the historical test
year, projected bridge forecast period and projected test period of \$21.3 million,
\$105.2 million and \$58.4 million respectively.

12

#### 13 Q52. Why was the Fermi 2 main unit generator rotor replaced in RF21?

14 A52. The Midcontinent Independent System Operator (MISO) identified that Trenton 15 Channel Unit 9 would be designated as a System Support Resource (SSR) unless an 16 alternative solution was identified to resolve violations of applicable reliability 17 criteria upon the unit's retirement. Replacement of the existing Fermi 2 main unit 18 generator rotor (and the generator excitation automatic voltage regulator (AVR) as 19 shown on line 12 of Exhibit A-12, Schedule B5.3, page 4) was required in 20 conjunction with replacement of Service System Transformer #65 (discussed later 21 in my testimony) prior to retirement of the Trenton Channel Power Plant in May of 22 2022 to resolve the reliability issues that would otherwise occur. The Fermi 2 23 generator rotor and AVR that were in-service prior to RF21 were not capable of 24 generating sufficient reactive power to solve the reliability issues identified by 25 MISO. RF21 was the Company's last window of opportunity to replace the Fermi 2

		J. C. DAVIS
Line <u>No.</u>		U-21297
1		generator rotor to maintain the Trenton Channel Unit 9 planned 2022 retirement date
2		as required by the 2020 Consent Decree between the Company and the United States
3		Environmental Protection Agency.
4		
5	Q53.	What is the basis to replace the Fermi 2 main unit generator in RF22?
6	A53.	The existing Fermi 2 generator (stator) is the original plant equipment,
7		manufactured in the early 1970s using the technology of that time. The generator
8		stator is approaching end of life (EOL). To date, multiple known vulnerabilities and
9		degradation have been mitigated through increased maintenance bridging strategies;
10		however, design vulnerabilities associated with the stator continue to represent
11		increased risk for sudden failure. Unplanned or unexpected failures not only present
12		a generation risk but also present operational risk to the plant operators responsible
13		for maneuvering the plant to a shutdown condition following a generator failure.
14		
15		A matched rotor will be installed in RF22 for two reasons: (1) a matched rotor can
16		be fit with the replacement stator prior to field work during RF22 which minimizes
17		project execution risk and (2) the current rotor installed in RF21 may be
18		contaminated with metallic particles after use with the original stator and its design
19		flaw which could jeopardize the integrity of the replacement stator if the current
20		rotor were to be reinstalled.
21		
22		DTE Electric continues the necessary work to complete the replacement stator and
23		have the replacement main unit generator (stator and rotor) in a ready state.
24		Implementing the Main Unit Generator Replacement project in RF22 is a reasonable
25		and prudent action because of the current state described above. DTE Electric has

1 implemented and will continue to implement reasonable and prudent bridging 2 strategies to mitigate the short-term reliability risks associated with the existing 3 Fermi 2 main unit generator; however, given the main unit generator's importance 4 with respect to safe and reliable plant operations through 2045, DTE Electric has 5 scheduled implementation of the Main Unit Generator Replacement project in 6 RF22. 7 8 Q54. What are the expenditures and rationale for the Service System Transformer 9 #65 and #69 Replacements project shown on line 3 of Exhibit A-12, Schedule 10 B5.3, page 4? 11 A54. The Service System Transformer #65 (SST65) and Service System Transformer #69 12 (SST69) capital expenditures for the historical test year, projected bridge forecast 13 period and projected test period are \$10.5 million, \$10.3 million and \$0.0 million 14 respectively. The purpose of SST65 and SST69 is to supply electrical loads to plant equipment essential for safe plant operation. The SST65 was replaced in RF21. The 15 16 transformer was replaced to ensure power supplied remained properly conditioned 17 with the Trenton Channel Power Plant retirement. As I explained earlier, MISO 18 identified that Trenton Channel Unit 9 would be designated as a SSR unless an 19 alternative solution was identified to resolve violations of applicable reliability 20 criteria upon the unit's retirement. Replacement of SST65 was the solution 21 identified to resolve the reliability issues and was required prior to the retirement of 22 the Trenton Channel Power Plant in May of 2022.

23

The SST69 replacement transformer, which has already been procured and delivered
to the Fermi 2 site, is currently not installed and not in service and is currently being

1		used as the spare transformer for SST65. The SST69 transformer replacement will
2		occur in a future refueling outage; expenditures for the implementation of the
3		replacement of SST69 are beyond the projected test period and not included in this
4		proceeding. The SST69 replacement is ultimately necessary to restore margins to
5		the SST69 equipment loads in certain low-voltage scenarios.
6		
7	Q55.	Can you discuss the expenditures and rationale for the Underground Safety-
8		Related Service Water Piping project shown on line 4 of Exhibit A-12, Schedule
9		B5.3, page 4?
10	A55.	The Underground Safety-Related Service Water Piping capital expenditures for the
11		historical test year, projected bridge forecast period and projected test period are
12		\$10.2 million, \$34.4 million and \$21.7 million respectively. The Underground
13		Safety-Related Service Water Piping project replaces nuclear safety-related piping
14		that delivers cooling water to various components that support the operation of the
15		nuclear reactor. A portion of the underground safety-related service water piping
16		was replaced in RF21, with the remaining piping to be completed in RF22. The
17		replacement of the underground safety-related service water piping is necessary to
18		address age-related degrading pipe-wall thickness and to ensure this pipe will
19		continue to support plant operations through the end of the operating license in 2045.
20		
21	Q56.	What does it mean to be "safety-related" piping?

A56. In the U.S. nuclear industry, the term "safety-related" applies to systems, structures,
 components, procedures, and controls that are relied upon to remain functional
 during and following design-basis events. Per NRC regulations, materials,
 equipment and components of safety-related systems have very strict manufacturing

tolerances and quality control; new materials, equipment and components are
inspected against technically developed procurement specifications. Post-delivery
modifications to safety-related materials such as cutting, fitting and welding pipe
must be to design, properly controlled, traceable, and work inspected by qualified
inspectors. Work on safety-related equipment requires an exactness in performance
that is not common in non-nuclear industry.

7

8

9

### Q57. Can you discuss the expenditures and rationale for the Torus Vent Header project depicted on line 5 of Exhibit A-12, Schedule B5.3, page 4?

10 A57. The Torus Vent Header project capital expenditures for the historical test year, 11 projected bridge forecast period and projected test period are \$9.4 million, \$34.1 12 million and \$0.0 million respectively. The torus vent header is a ring header located 13 within the torus structure and is designed to distribute water/steam into the torus as 14 steam is released from safety relief valves during a postulated accident scenario; like 15 the torus structure, the torus vent header has a specialized internal coating to protect 16 the torus vent header pipe from corrosion. The torus vent header coating had reached 17 the end of its useful life and was replaced in RF21. The torus vent header coating 18 replacement project was a reasonable and prudent action to support continued safe 19 and reliable operations of the Fermi 2 Power Plant.

20

### Q58. Can you discuss the expenditures and rationale for the Reactor Building Freight Elevator shown on line 6 of Exhibit A-12, Schedule B5.3, page 4?

A58. The Reactor Building (RB) Freight Elevator project capital expenditures for the
historical test year, projected bridge forecast period and projected test period are
\$8.6 million, \$1.9 million, and \$0.0 million respectively, do not extend beyond the

1		projected test period, addressed aging and obsolescence, and supported the
2		necessary replacement of the RB freight elevator and auxiliary systems. The RB
3		freight elevator is a 6,000-pound capacity Passenger/ Service Class A elevator
4		located in the Fermi 2 Reactor Building adjacent to the Fermi 2 drywell and spent
5		fuel pool. The purpose of Fermi 2 RB freight elevator is to provide access to the RB
6		sub-basement, Basement, first floor (RB1), second floor (RB2), RB3, RB4 and RB5
7		(total vertical travel is approximately 144').
8		
9	Q59.	Why was it necessary to replace the previous RB freight elevator?
10	A59.	The previous RB freight elevator was original to plant construction dating back to
11		the 1970s. An elevator such as the RB freight elevator could be expected to have a
12		service life of approximately $20 - 25$ years and the previous RB freight elevator had
13		been in service for almost double that period. Replacement parts were no longer
14		manufactured and reliability had declined with age (for example, doors would fail
15		to open, the elevator would get stuck between floors, and the elevator would go to
16		the wrong floor); when an elevator is used as the primary means of transporting low
17		level radioactive waste and other nuclear equipment – these reliability issues are not
18		acceptable.
19		
20		Additionally, the previous RB freight elevator did not meet modern safety codes

Additionally, the previous RB freight elevator did not meet modern safety codes such as State of Michigan Elevator Code Act 227 & 333, ASME A17.1, and NFPA 72, 70 & 80. Replacement of the RB freight elevator (which is now complete) allowed the new elevator and auxiliaries to meet these modern standards.

24

### Q60. What were the special factors associated with replacing the RB freight elevator that may not be common to other industries?

3 A60. Because the RB freight elevator is in the Fermi 2 RB (adjacent to the unit's drywell 4 and spent fuel pool), the replacement had to be performed in accordance with Fermi 5 2's strict modification and configuration control measures, which I discussed earlier. 6 The RB itself is in the Fermi 2 Radiological Protected Area (RPA) which requires 7 workers to achieve special access and qualifications to perform work in the area and 8 on this equipment. All workers inside the RPA must be cognizant of radiological 9 contaminants as well as general radiological dose rates while working in the RB. 10 Also, to perform daily RB ingress and egress, workers must pass through security 11 checkpoints, radiation protection checkpoints and receive proper radiological 12 protection briefs. The total project expenditures account for these special factors and 13 are reasonable and prudent.

14

15 Q61. Can you discuss the expenditures and rationale for the Feed Water Heaters 16 **Replacements project shown on line 8 of Exhibit A-12, Schedule B5.3, page 4?** 17 A61. The Feed Water Heaters Replacements capital expenditures for the historical test 18 year, projected bridge forecast period and projected test period are \$7.7 million, 19 \$10.0 million and \$4.7 million respectively. The Feed Water Heaters Replacements 20 project replaces six of Fermi 2's twelve feed water heaters that condition the nuclear 21 feed water for return to the reactor core. The six feed water heaters will be replaced 22 during RF23 (spring 2026) and RF24 (spring 2028); the remaining six feed water 23 heaters experience less operational stress and do not require replacement at this time. 24 The replacement of these feed water heaters, which are original plant equipment, is 25 necessary to address normal end-of-life degradation and improve operational

1 margins. Additionally, internal degradation of the existing feed water heaters 2 contributes to radiological dose rates in the plant. The new feed water heaters are 3 being constructed from materials that, as they wear and degrade during operation, 4 will not contribute radiological dose.

5

#### 6 Q62. Are there logistical complexities associated with the replacement of the feed 7 water heaters?

8 A62. These feed water heaters are quite large and are in enclosed rooms within Fermi 2 9 Turbine Building, surrounded by pipes. To get these feed water heaters into the 10 Turbine Building requires disassembly of the east wall of the Turbine Building and 11 relocation of structures within the building. Additionally, each of the piping 12 interferences must be removed from the feed water heater rooms to allow the 13 existing feed water heaters enough space to be removed and new feed water heaters 14 moved into place; the interference piping must then be restored along with the 15 Turbine Building wall prior to unit startup.

16

#### 17

#### Q63. Can you discuss the expenditures and rationale for the General Service Water 18 (GSW) intake groin replacement shown on line 9 of Exhibit A-12, Schedule 19 B5.3, page 4?

20 A63. The General Service Water (GSW) intake groin replacement project capital 21 expenditures for the historical test year, projected bridge forecast period and 22 projected test period are \$4.5 million, \$2.0 million, and \$4.7 million respectively, 23 do not extend beyond the projected test period, address natural erosion of the 24 existing GSW intake groin structure, and support the necessary replacement of the 25 GSW intake groin structure. The Fermi 2 GSW intake groin structure is comprised 1 of two armored-earthen jetties that jut into Lake Erie; the jetties' armor is rock and 2 concrete tetrapods which are designed to mitigate Lake Erie erosion action and yet 3 allow enough movement within the armor structure itself to mitigate Lake Erie ice 4 action from damaging the armor. The purpose of Fermi 2 GSW intake groin 5 structure is to protect the Fermi 2 GSW intakes from Lake Erie wave action, 6 minimize bio-material accumulation at the GSW intake and to minimize sediment 7 accumulation at the GSW intake; the Fermi 2 GSW system itself provides cooling 8 water to plant equipment; unplanned or unrecoverable loss of the GSW would 9 challenge plant operator's ability to safely operate the Fermi 2 plant.

10

Line

No.

### Q64. Can you discuss the expenditures and rationale for the Transformer Replacements shown on line 10 of Exhibit A-12, Schedule B5.3, page 4?

13 A64. The Transformer Replacements project capital expenditures for the historical test 14 year, projected bridge forecast period and projected test period are \$2.9 million, \$2.1 15 million, and \$5.8 million respectively, do not extend beyond the projected test 16 period, address an operational vulnerability, and support the necessary replacement 17 of the fifteen 4160V/480V dry transformers. The existing transformers (all 18 manufactured prior to 1988) have a latent manufacturing vulnerability – described 19 in an NRC 10 CFR Part 21 notification - where the operating voltage stresses exceed 20 the transformer's insulation design electric strength which makes the transformers 21 susceptible to premature failure. While Fermi 2's dry transformers are currently safe 22 to operate, the 10 CFR Part 21 notification recommends replacement of the affected 23 transformers to remove the operational vulnerability associated with premature 24 transformer failure. The purpose of these transformers is to supply conditioned 25 480V AC electricity to Fermi 2's safety and non-safety-related equipment;

Line

<u>No.</u>

1

2

3

unplanned or unrecoverable loss of these transformers would result in loss of equipment necessary for the safe operation of the Fermi 2 Power Plant and entry into an unplanned forced outage.

4

# Q65. Can you discuss the expenditures and rationale for the License Renewal Implementation (LRI) project shown on line 11 of Exhibit A-12, Schedule B5.3, page 4?

8 A65. The License Renewal Implementation (LRI) project capital expenditures for the 9 historical test year, projected bridge forecast period and projected test period are 10 \$2.9 million, \$15.2 million, and \$8.5 million respectively, do extend beyond the 11 projected test period, address DTE Electric's NRC renewed operating license 12 commitment, and support the necessary first-time and only-time inspection required 13 from Fermi 2 to operate during its Period of Extended Operations which begins in 14 2025. To ensure safe operations during a plant's Period of Extended Operation, the NRC mandates programs to monitor and intrusively inspect passive plant systems 15 16 that may be impacted by plant age; the Fermi 2 LRI project coordinates and conducts 17 the first-time and one-time inspections associated with this new and regulatorily-18 required monitoring and inspection regime; failure to complete these first-time and 19 one-time inspections would result in NRC violations and possible suspension of 20 Fermi 2's renewed operating license.

21

### Q66. Can you discuss the expenditures and rationale for the Boraflex Fuel Storage Racks project shown on line 13 of Exhibit A-12, Schedule B5.3, page 4?

A66. The Boraflex Fuel Storage Racks capital expenditures for the historical test year,
 projected bridge forecast period and projected test period are \$2.3 million, \$5.7

1		million and \$0.0 million respectively. The Boraflex fuel storage racks project will
2		replace the end-of-life Boraflex fuel storage racks with new neutron-absorbing
3		material. The replacement of the Boraflex fuel storage racks is an NRC commitment
4		tied to Fermi 2's license renewal and is necessary to restore safety margins for the
5		storage of the spent fuel through the end of the operating license in 2045.
6		
7	Q67.	Can you discuss the expenditures and rationale for the drywell cooler projects
8		shown on lines 14, 16 and 18 of Exhibit A-12, Schedule B5.3, page 4?
9	A67.	These drywell cooler projects are part of a staged, multi-year effort to proactively
10		and systematically address a series of necessary drywell cooler replacements in a
11		manageable fashion based on risk of potential leakage. The replacements have been
12		grouped by refueling outage implementation. The replacement of these coolers is
13		necessary to address the normal end of life status and degradation of these coolers
14		which are original plant equipment. Excessive leakage from drywell coolers can
15		and have resulted in plant shutdowns to repair. Fermi 2 has 14 drywell coolers which
16		provide the containment structure that surrounds the reactor with atmospheric
17		cooling during normal operations.
18		
19		Drywell Coolers #10 and #14, as depicted on line 18, were replaced in RF20 in the
20		spring of 2020 and have capital expenditures for the historical test year, projected
21		bridge forecast period and projected test period of \$0.4 million, \$0.0 million and
22		\$0.0 million respectively.
23		

	U-21297			
	Drywell Coolers #12 and #13, as depicted on line 14, were replaced in RF21 and			
	have capital expenditures for the historical test year, projected bridge forecast pe			
	and projected test period of \$1.7 million, \$3.4 million and \$0.0 million respectively.			
	Drywell Cooler #8 is depicted on line 16, is on hold and is forecasted to be replaced			
	in either RF23 or RF24 and has capital expenditures for the historical test year,			
	projected bridge forecast period and projected test period of \$1.0 million, \$1.5			
	million and \$0.0 million respectively.			
Q68.	Are there additional complexities associated with the replacement of the			
	drywell coolers?			
A68.	The drywell coolers are located in the Fermi 2 drywell. The drywell immediately			
	surrounds the reactor pressure vessel and its environment is typically characterized			
	by high temperatures, radiologically contaminated surfaces and significant			
	radiological dose presence with densely configured plant equipment; while sealed			
	from entry during normal plant operations due to an inert nitrogen atmosphere, the			
	from entry during normal plant operations due to an inert nitrogen atmosphere, the drywell does have two equipment hatches and a personnel hatch to allow equipment			
	from entry during normal plant operations due to an inert nitrogen atmosphere, the drywell does have two equipment hatches and a personnel hatch to allow equipment and workers into the drywell during refueling outages. The travel paths for the			
	from entry during normal plant operations due to an inert nitrogen atmosphere, the drywell does have two equipment hatches and a personnel hatch to allow equipment and workers into the drywell during refueling outages. The travel paths for the drywell coolers can be complex with many interferences that must be navigated			
	from entry during normal plant operations due to an inert nitrogen atmosphere, the drywell does have two equipment hatches and a personnel hatch to allow equipment and workers into the drywell during refueling outages. The travel paths for the drywell coolers can be complex with many interferences that must be navigated using potentially complex lifting and rigging evolutions or removed and later			
	from entry during normal plant operations due to an inert nitrogen atmosphere, the drywell does have two equipment hatches and a personnel hatch to allow equipment and workers into the drywell during refueling outages. The travel paths for the drywell coolers can be complex with many interferences that must be navigated using potentially complex lifting and rigging evolutions or removed and later reinstalled to successfully replace the coolers. Work must be highly scripted by			
	from entry during normal plant operations due to an inert nitrogen atmosphere, the drywell does have two equipment hatches and a personnel hatch to allow equipment and workers into the drywell during refueling outages. The travel paths for the drywell coolers can be complex with many interferences that must be navigated using potentially complex lifting and rigging evolutions or removed and later reinstalled to successfully replace the coolers. Work must be highly scripted by qualified individuals to address plant configuration challenges, minimize			
	from entry during normal plant operations due to an inert nitrogen atmosphere, the drywell does have two equipment hatches and a personnel hatch to allow equipment and workers into the drywell during refueling outages. The travel paths for the drywell coolers can be complex with many interferences that must be navigated using potentially complex lifting and rigging evolutions or removed and later reinstalled to successfully replace the coolers. Work must be highly scripted by qualified individuals to address plant configuration challenges, minimize radiological dose, and minimize human performance errors.			

Line No.

#### J. C. DAVIS U-21297

## Q69. Can you discuss the expenditures and rationale for the Circulating Water (CW) Discharge Pipe project shown on line 17 of Exhibit A-12, Schedule B5.3, page 4?

A69. The Circulating Water (CW) Pipe project capital expenditures for the historical test 4 5 year, projected bridge forecast period and projected test period are \$0.7 million, \$5.7 6 million, and \$6.0 million respectively, extend beyond the projected test period, 7 address natural aging of the Fermi 2 CW discharge piping, and support the necessary 8 in situ replacement of the CW discharge piping pressure boundary with a carbon-9 fiber shell that lines the interior surface of the CW discharge pipe. The Fermi 2 CW 10 piping is two interconnected sets of underground 144" diameter, pre-stressed 11 concrete cylinder pipe; total pipe length is approximately a mile and comprised of 12 approximately 450 pipe segments. The purpose of Fermi 2 CW piping is to transport 13 circulating water from the CW pond to the Main Unit Condenser (CW inlet piping) 14 and to transport the circulating water from the Main Unit Condenser to the Fermi 2 15 natural draft cooling towers (CW discharge piping); the Fermi 2 CW system itself 16 provides cooling water to Main Unit Condenser; unplanned or unrecoverable loss 17 of the CW piping would challenge plant operator's ability to safely operate the 18 Fermi 2 plant and cause a unit shutdown.

19

### Q70. Why is it necessary to replace the pressure boundary of the CW discharge piping?

A70. The CW pipe is original to plant construction and is aging – as all underground
 concrete pipes do. The CW pipe is pre-stressed concrete cylinder pipe (PCCP) which
 has a concrete core, a thin steel cylinder, high tensile prestressing wires and a mortar
 coating. As PCCP ages the mortar will delaminate exposing the prestressing wires

Line <u>No.</u>		<b>J. C. DAVIS</b> U-21297
1		to corrosion forces; as the prestressing wires corrode, the strength of the PCCP
2		deteriorates and the PCCP will catastrophically fail.
3		
4		Because the failure mode of PCCP is catastrophic failure, the reaction time of plant
5		operators to safely maneuver the plant is greatly reduced. DTE Electric is taking the
6		reasonable and prudent approach to perform in situ replacement of the interior CW
7		pipe pressure boundary with a carbon-fiber liner, pipe segment by pipe segment,
8		over time and in stages based on priorities derived from inspections to minimize
9		refueling outage time.
10		
11	Q71.	Can you discuss the expenditures and rationale for the Radiation Monitors
12		project shown on line 21 of Exhibit A-12, Schedule B5.3, page 4?
13	A71.	The radiation monitors capital expenditures for the historical test year, projected
14		bridge forecast period and projected test period are \$0.1 million, \$9.1 million and
15		\$9.8 million respectively. The Radiation Monitors project replaces Fermi 2's
16		radiation monitor computer referred to as "SS1," as well as the plant's SPING
17		(detects particulate, iodine and noble gases) and AXM (accident range effluent
18		monitor) radiation monitors; together this radiation monitor system monitors and
19		analyzes the plant's gaseous effluents to affirm the plant's radiation levels remain
20		within proper specification. This radiation monitor system is credited in Fermi 2's
21		Emergency Response Plan due to its capacity to monitor and analyze potential
22		radioactive releases thus directly impacts recommendations provided to the state for
23		instituting emergency actions for the public in the event of an emergency. The
24		radiation monitor system will be replaced in phases throughout the bridge and test
25		period and is expected to be completed in 2025. The replacement of this radiation

monitor system, is necessary to address aging and obsolescence, reduce the resource
 and dose impact of compensatory sampling, and improve regulatory margins;
 unexpected or unrecoverable loss of this radiation monitor system could result in
 NRC enforcement action

5

### Q72. Can you discuss the expenditures and rationale for the Fire Header Restoration project shown on line 22 of Exhibit A-12, Schedule B5.3, page 4?

8 A72. The Fire Header Restoration project capital expenditures for the historical test year, 9 projected bridge forecast period and projected test period are \$0.1 million, \$3.5 10 million, and \$0.0 million respectively, extend beyond the projected test period, 11 address natural aging of the Fermi 2 fire header piping, and support the necessary 12 replacement of the Fermi 2 fire header piping. The Fermi 2 fire header piping is 13 approximately 5000' of underground "ring header" comprised of 12" unlined, 14 ductile iron pipe that routes around the Fermi 2 Power Plant and a separate 6" header 15 for the station blackout diesels. The purpose of Fermi 2 fire header is to distribute 16 firefighting water from the normal or alternate sources of water to the scene of a 17 postulated fire; with fire being one of the most consequential events at a nuclear 18 power plant, unplanned or unrecoverable loss of the fire header piping would 19 challenge plant operator's ability to safely operate the Fermi 2 plant.

20

#### 21 Q73. Why is it necessary to replace the Fermi 2 fire header?

A73. Normal aging. The fire header pipe is original to plant construction and is
 approaching fifty years of in-service time. As a fire header, the piping is exposed to
 raw lake water which degrades the interior surfaces of the pipe, causing leaks and
 loss of water pressure. The existing fire header pipe would not support safe and

1		reliable operations through Fermi 2's current operating life ending in 2045. DTE
2		Electric is taking the reasonable and prudent approach to replace the fire header pipe
3		over time and in stages based on priorities derived from inspection and testing; this
4		also allows for minimal fire header outage time and minimal operational
5		compensatory measures to protect the plant while replacement is occurring.
6		
7	Q74.	Do any of the projects listed in Exhibit A-12, Schedule B5.3, pages 2-4 contain
8		contingency amounts?
9	A74.	No. The capital expenditures as shown in Exhibit A-12, Schedule B5.3, pages 2-4
10		do not include contingencies. The capital expenditures shown in Exhibit A-12,
11		Schedule B5.3, pages 2-4 are good faith estimates (without contingencies) based on
12		relevant data available using reasonable and prudent forecasting methods.
13		
14	Q75.	How does the Nuclear Generation organization manage its capital expenditures
15		without contingencies?
16	A75.	Nuclear Generation manages total capital expenditures for the period and expects
17		that capital expenditures in total will be incurred as projected. In general, Nuclear
18		Generation maintains a prioritized list of projects such that as project forecasts are
19		over or under expected amounts, Nuclear Generation uses this prioritized list
20		consistent with the key principles I described earlier to manage the Nuclear
21		Generation portfolio of projects.
22		
23	<u>Nucle</u>	ear Fuel Capital Expenditures
24	Q76.	Can you explain Total Nuclear Fuel summarized on line 10 of Exhibit A-12,
25		Schedule B5.3, page 1?

Line <u>No.</u>		<b>J. C. DAVIS</b> U-21297
1	A76.	Yes. Total Nuclear Fuel includes those capital expenditures for the various
2		components of the nuclear fuel cycle: (1) Uranium, (2) Conversion, (3) Enrichment
3		and (4) Fabrication.
4		
5		Uranium refers to the costs associated with mining and milling uranium. Natural
6		uranium is obtained from the exploration and mining of uranium ore. Milling is the
7		mechanical and chemical process of extracting uranium from the mined ore in the
8		form of U3O8, commonly referred to as yellowcake. The U3O8 is the feed material
9		for the conversion process.
10		
11		Conversion refers to the costs associated with chemically converting U3O8 into
12		UF6, uranium hexafluoride. The UF6 is the gaseous compound used as a feed in the
13		enrichment process.
14		
15		Enrichment refers to the costs to enrich the uranium from a natural 0.7% U235
16		content to a 4% to 5% U235 content required for light water reactor fuel. The
17		enriched UF6 is used as a feed in the fabrication process.
18		
19		Fabrication refers to the chemical conversion of the enriched UF6 to UO2 (uranium
20		dioxide) powder which is then pressed and sintered into hard ceramic fuel pellets
21		that are loaded into long, narrow zirconium alloy tubes called fuel rods; fuel rods
22		are then assembled into fuel bundles using spacers and end fittings to hold the fuel
23		rods together. The Fermi 2 reactor core requires 764 of these fuel bundles to operate.
24		

1		The amount of fuel purchased is determined by the design of the fuel and by the
2		expected generation during the life of the fuel. Nuclear fuel capital expenditures
3		were developed on the basis that Fermi 2 transitioned from its 18-month operating
4		cycle to the 24-month operating cycle following RF21 in winter/spring of 2022,
5		which occurred.
6		
7	Q77.	Can you explain the Total Nuclear Fuel expenditures as shown on Exhibit A-
8		12, Schedule B5.3, page 1, line 10?
9	A77.	Yes. The Total Nuclear Fuel capital expenditures for the historical test year,
10		projected bridge forecast period and projected test period are \$120.1 million, \$120.7
11		million and \$0.2 million respectively and are consistent with Fermi 2's projections
12		in the Company's 2023 PSCR Plan in Case No. U-21259.
13		
14	Q78.	Can you explain why Total Nuclear Fuel expenditures vary from year-to-year?
15	A78.	Yes. Total Nuclear Fuel expenditures vary from year-to-year because Fermi 2
16		operates on a 24-month fuel cycle and fuel expenditures occur at relatively fixed
17		points in time relative to that 24-month fuel cycle (most nuclear fuel capital
18		expenditures occur approximately six months prior to a refueling outage); therefore,
19		Total Nuclear Fuel capital expenditures can be expected to oscillate on a two-year
20		pattern.
21		
22	Q79.	How would you characterize the level of expenditures for Fermi 2's Total
23		Nuclear Fuel?
24	A79.	Fermi 2's fuel expenditures are reasonable and prudent. I expect fuel expenditures
25		to continue to be reasonable as the Company has secured the necessary uranium,

Line <u>No.</u>		<b>J. C. DAVIS</b> U-21297
1		conversion, enrichment and fabrication through the projected test period ending
2		November 30, 2024.
3		
4	AFU	DC Forecast
5	Q80.	Can you explain the Allowance for Funds Used During Construction (AFUDC)
6		as shown in Exhibit A-12, Schedule B5.3, page 5?
7	A80.	Nuclear Generation capital expenditures include an Allowance for Funds Used
8		During Construction (AFUDC) for eligible projects that are in Construction Work
9		in Progress (CWIP); eligible projects are those projects greater than \$50,000 and
10		lasting more than six months. The actual historical period Total AFUDC – Nuclear
11		Production Plant was \$10.5 million as shown in Exhibit A-12, Schedule B5.3, page
12		5, line 25, column (b). The forecasted Total AFUDC – Nuclear Production Plant for
13		the projected test period is \$8.5 million as shown in Exhibit A-12, Schedule B5.3,
14		page 5, line 25, column (c).
15		
16	Q81.	How did you forecast the AFUDC as shown in Exhibit A-12, Schedule B5.3,
17		page 5?
18	A81.	The Nuclear Production Plant - Routine Expenditures AFUDC forecast uses a
19		historical trend to estimate AFUDC as the mix of eligible projects is fairly consistent
20		year-to-year. The Nuclear Production Plant - Project Specific AFUDC forecast
21		explicitly calculates AFUDC for eligible projects using project-specific CWIP
22		balances multiplied by the AFUDC rate where the AFUDC rate is the authorized
23		cost of capital rate of 5.417% consistent with the November 18, 2022, Case No. U-
24		20836 rate order.
25		

Line <u>No.</u>		<b>J. C. DAVIS</b> U-21297
1		<b>Removal Costs, Plant in Service and CWIP Forecast</b>
2	Q82.	What is provided on the schedule entitled Removal Costs, Plant in Service and
3		CWIP schedule on Exhibit A-12, Schedule B5.3, page 6?
4	A82.	This schedule provides a breakdown of plant activities which are used by Witness
5		Uzenski to forecast Plant in Service, Accumulated Depreciation and Construction
6		Work in Progress (CWIP) on the projected balance sheet.
7		
8		Capital expenditures consistent with page 1 are summarized in columns (c) through
9		(f). Routine and Non-Routine projects are shown on Lines 1 and 2, while Fermi 2
10		License Renewal has been identified separately on line 4 because this is recorded to
11		Plant Held for Future Use. Column (b) includes a corresponding in-service
12		assumption: "Annual" is indicated for both routine and non-routine spend because
13		these projects are generally unitized within the year of spend.
14		
15		Column (g) includes an estimated percentage of removal costs that are included
16		within the capital expenditures. Removal costs, as discussed by Witness Uzenski,
17		are charged to Accumulated Depreciation rather than Plant/ CWIP and are therefore
18		not depreciable. Removal cost of 15% based on historical trend of removals as a
19		component of capital expenditures is applied to expenditures on lines 1 and 2.
20		
21		Column (h) through (j) reflect calculated removal costs based on projected Capital
22		Expenditures in columns (d) through (f) multiplied by the removal cost percentage
23		in column (g). The remaining Capital Expenditures will appear in Plant in Service
24		columns (k) through (m) since the in-service assumption is "Annual." The CWIP
25		columns (n) through (p) show there is no significant CWIP activity.

Line		<b>J. C. DAVIS</b> U-21297
<u>1</u>		
2	2021	_ 2024 Capital Projects Summary
2	083	What is your opinion regarding the reasonableness of the forecasted capital
3	Q03.	what is your opinion regarding the reasonableness of the forecasted capital
4	4.02	expenditures for Nuclear Generation?
5	A83.	I believe the forecasted capital expenditures for Nuclear Generation are reasonable
6		and prudent. I believe the forecast as depicted by line 11 of Exhibit A-12, Schedule
7		B5.3, page 1, accurately represents the capital expenditures that can reasonably be
8		expected to continue operation of nuclear assets of similar age and vintage. My
9		summation of projects reflects DTE Electric's commitment to ensure the safe and
10		reliable operation of Fermi 2 through its current operating license expiration in 2045.
11		As I have expressed previously, these capital expenditures are prudent and
12		reasonable given the regulations, goals and conditions under which Fermi 2
13		operates.
14		
15	Nucle	ear Generation O&M Expense
16	Q84.	Can you provide an outline of your Nuclear Generation O&M discussion?
17	A84.	Yes. My testimony will begin with the O&M Expenses Overview and then discuss
18		and support the additional details regarding:
19		Rate Case Adjustments
20		Adjusted Historical Test Period
21		Projected Adjustments
22		
23	<u>0&amp;N</u>	I Expenses Overview
24	Q85.	Can you provide an overview of the Nuclear Generation O&M expenses
25		supported by your testimony?

1	A85.	Exhibit A-13, Schedule C5.3, page 1, line 24 from left to right depicts the O&M
2		expenses for the 12-month historical test period ended December 31, 2021,
3		adjustments to the historical test period and then the forecasted O&M expenses for
4		the 12-month projected test period ending November 30, 2024.
5		
6		The actual O&M expenses by FERC account for the 12-month historical test period
7		ended December 31, 2021 were \$206.5 million as shown in column (c). Rate case
8		adjustments are made in column (d) to reduce O&M by \$27.4 million to account for
9		the Nuclear Surcharge, in column (e) to reclassify Project Evaluation Review
10		Committee (PERC) nuclear O&M project expenditures and in column (f) to reduce
11		O&M by \$0.1 million to normalize 2021 actual PERC O&M expenses to the \$15.0M
12		PERC O&M base. Due to the relatively small amount, DTE Electric expensed the
13		\$0.1 million above the 2022 \$15.0M PERC O&M base rather than convert the \$0.1
14		million to the Regulatory Asset - PERC. These rate case adjustments result in \$179.0
15		million of adjusted O&M for the 2021 historical test period as shown in column (g).
16		
17		Projected adjustments of \$5.3 million, \$4.9 million and \$4.2 million in columns (h),
18		(i) and (j) respectively account for inflation. The \$7.9 million decrease in column
19		(k) is subtracted to account for outage accrual adjustments and O&M is reduced by
20		\$8.5 million in column (1) to account for the total PERC expense in the forecasted
21		test period as supported by calculations performed by Company Witness Uzenski.
22		These projected adjustments yield a total change of \$2.0 million as shown in column
23		(m).
24		

		J. C. DAVIS
Line <u>No.</u>		U-21297
1		With the above adjustments, the forecasted O&M expenses for the 12-month
2		projected test period are \$177.0 million as shown in column (n).
3		
4	Q86.	What projected Total Nuclear Power Generation O&M expenses are you
5		supporting?
6	A86.	I am supporting projected Total Nuclear Power Generation O&M expenses of
7		\$177.0 million as shown in Exhibit A-13, Schedule C5.3, line 24, column (n) as
8		reasonable and prudent.
9		
10	<u>Rate</u>	Case Adjustments
11	Q87.	Can you explain the basis for the Rate Case Adjustments in column (d) of
12		Exhibit A-13, Schedule C5.3, page 1?
13	A87.	Site security and radiation protection costs were removed from base rates and
14		recognized in the Nuclear Surcharge as established in DTE Electric Case No. U-
15		14399. The Nuclear Surcharge reduction of \$27.4 million as summed on line 24,
16		column (d) accomplishes this requirement. The complete elimination of all financial
17		statement impacts of the Nuclear Surcharge are supported by Witness Uzenski.
18		
19	Q88.	Can you explain the basis for the Rate Case Adjustments in column (e) of
20		Exhibit A-13, Schedule C5.3, page 1?
21	A88.	The Reclassify PERC adjustment nets to zero as shown on line 24, column (e). This
22		reclassification is performed to make explicit the \$15.1 million PERC Base Expense
23		shown on line 21, column (e) and the \$16.3 million of PERC Regulatory Asset
24		amortization shown on line 22, column (e) are not inflated in the projected

Line No.		<b>J. C. DAVIS</b> U-21297
1		adjustments. I will explain the PERC Regulatory Asset mechanism later in my
2		testimony.
3		
4	<u>Adju</u>	sted Historical Test Period
5	Q89.	Can you explain the components that constitute the actual Total Nuclear Power
6		Generation O&M expenses for adjusted historical test period in line 24, column
7		(f) of Exhibit A-13, Schedule C5.3, page 1?
8	A89.	Total Nuclear Generation O&M of \$179.0 million consists of the Nuclear
9		Organization, PERC Base Expense, amortization of the PERC Regulatory Asset,
10		regulatory assessments and dues, and refueling outage expenses. I detail these
11		expenses for the 2021 historical period on page 2 of Exhibit A-13, Schedule C5.3.
12		
13	Q90.	What is the need for and basis of the "Nuclear Organization" expenses that are
14		included in the 2021 historic period for Operation and Maintenance Expenses
15		on Exhibit A-13, Schedule C5.3, page 2, line 1?
16	A90.	Nuclear Organization expenses are the baseline employee, services and material
17		expenses required to safely and reliably operate Fermi 2. The Nuclear Organization
18		expenses for the historical test period ended December 31, 2021 were \$111.0
19		million.
20		
21	Q91.	What is the need for and basis for the "PERC Base Expense" expenses that are
22		included in the 2021 historic period for Operation and Maintenance Expenses
23		on Exhibit A-13, Schedule C5.3, page 2, line 2?
24	A91.	As explained and supported by Witness Uzenski, the Commission Order in Case
25		No. U-18014 approved an annual base level of PERC expenses of \$4.9 million for

<b>.</b> .		J. C. DAVIS
Line <u>No.</u>		0-21297
1		nuclear O&M projects and the Commission Order in Case No. U-20561 increased
2		the approved annual base level of PERC expenses to \$15.0 million; the PERC Base
3		Expense of \$15.0 million depicted on line 2 recognizes those approvals.
4		
5	Q92.	What is the need for and basis for the "Reg Asset Amortization - PERC"
6		expenses that are included in the 2021 historic period for Operation and
7		Maintenance Expenses on Exhibit A-13, Schedule C5.3, page 2, line 3?
8	A92.	As explained and supported by Witness Uzenski, the Commission Order in Case
9		No. U-18014 approved a regulatory asset for annual PERC projects O&M
10		expenditures that exceed the annual base level of PERC expenses of \$4.9 million
11		for nuclear O&M projects. In Case No. U-20561, the Commission Order updated
12		the approved regulatory asset for annual PERC projects O&M expenditures that
13		exceed the annual base level of PERC expenses of \$15.0 million for nuclear O&M
14		projects. The Order in Case No. U-18014 established the amortization period of this
15		regulatory asset as five years. Consistent with that Order, the \$16.3 million depicted
16		on line 3 is the amount of the PERC Regulatory Asset amortized in 2021.
17		
18	Q93.	What is the need for and basis for the "Regulatory Assessments and Dues"
19		expenses that are included in the 2021 historic period for Operation and
20		Maintenance Expenses on Exhibit A-13, Schedule C5.3, page 2, line 4?
21	A93.	A majority of these assessments and dues are regulatory driven, such as those
22		assessments and dues required by the NRC to cover oversight of the plant. In
23		addition, assessments and dues are associated with licensing requirements including
24		the Emergency Response Organization (ERO) and various industry groups.
25		
1		Industry groups include the Institute of Nuclear Power Operations (INPO), which
--	--	--
2		assists utilities in operating nuclear plants to the highest safety standards, the
3		Nuclear Energy Institute (NEI), which assists in common issues impacting the
4		nuclear industry, as well as the Electric Power Research Institute (EPRI) and the
5		General Electric Boiling Water Reactor Owners' Group, both of which sponsor
6		research that is used by nuclear plants to operate more safely and economically.
7		
8		The ERO supports the Fermi 2 Emergency Plan which is a license requirement
9		necessary to ensure the health and safety of the public during emergency response
10		events. The ERO funds federal, state and local county emergency facilities in
11		support of the Fermi 2 Emergency Plan.
12		
13	004	Which assassments and dues are non-discretionary (i.e. mondated)?
15	<b>۲</b> ۰ري	which assessments and dues are non-discretionary (i.e. manuated):
14	<b>A</b> 94.	NRC, INPO and ERO assessments and dues are non-discretionary.
14 15	A94.	NRC, INPO and ERO assessments and dues are non-discretionary.
14 15 16	Q94. A94. Q95.	<ul><li>Which assessments and dues are non-discretionary (i.e. mandated):</li><li>NRC, INPO and ERO assessments and dues are non-discretionary.</li><li>Why does the Company pay the discretionary assessments and dues?</li></ul>
14 15 16 17	<b>Q94.</b> A94. <b>Q95.</b> A95.	<ul> <li>Which assessments and dues are non-discretionary (i.e. manuated):</li> <li>NRC, INPO and ERO assessments and dues are non-discretionary.</li> <li>Why does the Company pay the discretionary assessments and dues?</li> <li>Although not specifically mandated, voluntary participation with organizations such</li> </ul>
14 15 16 17 18	<b>Q94.</b> <b>Q95.</b> A95.	<ul> <li>Which assessments and dues are non-discretionary (i.e. mandated):</li> <li>NRC, INPO and ERO assessments and dues are non-discretionary.</li> <li>Why does the Company pay the discretionary assessments and dues?</li> <li>Although not specifically mandated, voluntary participation with organizations such as EPRI and NEI are critical within a nuclear business model. In particular,</li> </ul>
14 15 16 17 18 19	<b>Q94.</b> <b>Q95.</b> A95.	<ul> <li>Which assessments and dues are non-discretionary (i.e. manuated):</li> <li>NRC, INPO and ERO assessments and dues are non-discretionary.</li> <li>Why does the Company pay the discretionary assessments and dues?</li> <li>Although not specifically mandated, voluntary participation with organizations such as EPRI and NEI are critical within a nuclear business model. In particular, organizations like EPRI that support research and development include sharing of</li> </ul>
14 15 16 17 18 19 20	<b>Q94.</b> <b>Q95.</b> A95.	<ul> <li>When assessments and dues are non-discretionary (i.e. manuated):</li> <li>NRC, INPO and ERO assessments and dues are non-discretionary.</li> <li>Why does the Company pay the discretionary assessments and dues?</li> <li>Although not specifically mandated, voluntary participation with organizations such as EPRI and NEI are critical within a nuclear business model. In particular, organizations like EPRI that support research and development include sharing of products and services to ensure nuclear asset owners benefit as a whole from shared</li> </ul>
14 15 16 17 18 19 20 21	<b>Q94</b> . <b>Q95</b> . A95.	<ul> <li>When assessments and dues are non-discretionary (i.e. mandated):</li> <li>NRC, INPO and ERO assessments and dues are non-discretionary.</li> <li>Why does the Company pay the discretionary assessments and dues?</li> <li>Although not specifically mandated, voluntary participation with organizations such as EPRI and NEI are critical within a nuclear business model. In particular, organizations like EPRI that support research and development include sharing of products and services to ensure nuclear asset owners benefit as a whole from shared information. These products and services would be unaffordable without group</li> </ul>
14 15 16 17 18 19 20 21 22	<b>Q94.</b> <b>Q95.</b> A95.	<ul> <li>Why does the Company pay the discretionary assessments and dues?</li> <li>Although not specifically mandated, voluntary participation with organizations such as EPRI and NEI are critical within a nuclear business model. In particular, organizations like EPRI that support research and development include sharing of products and services to ensure nuclear asset owners benefit as a whole from shared information. These products and services would be unaffordable without group participation and funding. The role provided by NEI is valuable to plant owners and</li> </ul>
<ol> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>23</li> </ol>	<b>Q95.</b> A95.	<ul> <li>NRC, INPO and ERO assessments and dues are non-discretionary.</li> <li>Why does the Company pay the discretionary assessments and dues?</li> <li>Although not specifically mandated, voluntary participation with organizations such as EPRI and NEI are critical within a nuclear business model. In particular, organizations like EPRI that support research and development include sharing of products and services to ensure nuclear asset owners benefit as a whole from shared information. These products and services would be unaffordable without group participation and funding. The role provided by NEI is valuable to plant owners and operators in helping to shape important industry issues and regulation through a</li> </ul>
<ol> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>23</li> <li>24</li> </ol>	<b>Q94.</b> <b>Q95.</b> A95.	<ul> <li>NRC, INPO and ERO assessments and dues are non-discretionary.</li> <li>Why does the Company pay the discretionary assessments and dues?</li> <li>Although not specifically mandated, voluntary participation with organizations such as EPRI and NEI are critical within a nuclear business model. In particular, organizations like EPRI that support research and development include sharing of products and services to ensure nuclear asset owners benefit as a whole from shared information. These products and services would be unaffordable without group participation and funding. The role provided by NEI is valuable to plant owners and operators in helping to shape important industry issues and regulation through a coordinated and solidified approach. The nuclear industry clearly recognizes that</li> </ul>

		J. C. DAVIS
Line <u>No.</u>		U-21297
1		a result, this industry believes in significant group participation and knowledge
2		sharing to help preclude such an event.
3		
4	Q96.	What is the need for and basis for "Total Refueling Outage" expenses for the
5		2021 historical period on Exhibit A-13, Schedule C5.3, page 2, line 10?
6	A96.	As discussed earlier in my testimony, the Fermi 2 plant previously operated on an
7		18-month refueling cycle such that every 18 months Fermi 2 would shut down to
8		refuel the reactor. The "Total Refueling Outage" expenses are those costs necessary
9		to (1) refuel the Fermi 2 reactor and (2) perform offline maintenance to ensure Fermi
10		2 can operate safely and reliably for the next operating cycle.
11		
12		The "Total Refueling Outage" expense consists of the actual refueling outage costs
13		(line 7), the refueling outage accrual (line 8) and the refueling outage accrual
14		reversals (line 9) for the 2021 historical period. Line 10 nets these three components
15		and represents an accounting practice of levelizing incremental refueling expenses
16		by accruing the anticipated refueling expenses over the term of an operating cycle.
17		
18	Q97.	Why does DTE Electric levelize its incremental refueling outage expenses?
19	A97.	DTE Electric levelizes its incremental refueling outage expenses so that the
20		difference in expense between outage and non-outage years does not burden DTE
21		Electric customers with large rate fluctuations or create financial swings for the
22		Company. For example, if the Company bases the rate request on the projections
23		for a refueling outage year and all the expenses of that outage appear in that year's
24		projections, then the Company would be presenting an unnecessarily high cost of
25		providing Fermi 2 generation over the period the rates are in effect. The inverse is

JCD-57

Line <u>No.</u>		J. C. DAVIS U-21297
1		also true if the Company used a non-refueling outage year projection for the same
2		purpose. This is consistent with the treatment in prior cases where the Commission
3		has allowed levelized refueling outage expenses in setting rates.
4		
5	Q98.	What is the basis for the "Refuel Outage" expense at \$8.6 million for the 2021
6		historical period shown on Exhibit A-13, Schedule C5.3, page 2, line 7?
7	A98.	This is the actual refuel outage expenditures incurred in the 2021 historical period
8		for RF21.
9		
10	Q99.	How does DTE Electric manage incremental refueling outage expenses?
11	A99.	The Company manages incremental expenses through structured planning and
12		preparation that is consistent with industry standards and processes. We
13		implemented rigorous financial controls that supported daily management of
14		resources during the execution phase of the refueling outage. This management of
15		resources includes daily reviews of scope completion, schedule and budget. As work
16		completes, contracted resources exit promptly from the site to ensure that costs are
17		controlled.
18		
19	Q100	. What is the basis for the "Refuel Outage Accrual" expenses at \$25.1 million for
20		the 2021 historical period shown on Exhibit A-13, Schedule C5.3, page 2, line
21		8?
22	A100	. This is the actual amount accrued in the historical period for RF21.
23		
24	Q101	. What is the basis for the "Refuel Outage Reversal" of \$9.5 million for the 2021
25		historical period shown on Exhibit A-13, Schedule C5.3, page 2, line 9?

### JCD-58

1	A101. This is the actual amount of outage accrual that had been accrued in advance for
2	RF21 and credited to O&M in the historical test period to offset the \$8.6 million of
3	actual RF21 refuel outage expenditures shown on line 7 and discussed above.
4	
5	Projected Adjustments
6	Q102. Can you explain the basis for the inflation adjustments in columns (g), (h) and
7	(i) on line 24 of Exhibit A-13, Schedule C5.3, page 1?
8	A102. The labor and material prorated inflation adjustment rates of 3.6% for 2022, 3.2%
9	for 2023 and 2.9% for 2024 are supported by the testimony of Witness Uzenski.
10	Nuclear Generation applied these forecasted inflation rates to the adjusted historical
11	test period costs in column (g).
12	
13	Q103. Can you explain the basis for the Outage Accrual adjustment in column (k) on
14	line 24 of Exhibit A-13, Schedule C5.3, page 1?
15	A103. The Outage Accrual adjustment is to normalize the outage accrual for the projected
16	test period to approximately \$18.7 million. This Outage Accrual adjustment reflects
17	our commitment to improving refueling outage performance and reducing future
18	outage O&M expenditures.
19	
20	Q104. What duration have you projected for RF22?
21	A104. The 2023 PSCR Plan (Case No. U-21259) projected an outage duration of 45 days
22	for RF22 (projected for spring 2024).
23	
24	Q105. Can you explain the basis for the PERC Amortization adjustment in column
25	(l) on line 24 of Exhibit A-13, Schedule C5.3, page 1?

1	A105. As explained and supported by Witness Uzenski, the Commission Order in Case
2	No. U-18014 not only approved an annual base level of PERC expenses for nuclear
3	O&M projects, but also provided deferral and amortization treatment for any
4	expenses over or under the base amount. The PERC Base expense was changed by
5	\$10.1 million from \$4.9 million per year to \$15.0 million per year in the May 8,
6	2020, Commission Order in Case No. U-20561.
7	
8	The PERC Amortization reduction of \$8.5 million in column (1) on line 24 consists
9	of the \$0.0 million change in the approved annual PERC Base Expense as shown in
10	column (l) on line 21 and a forecasted reduction of \$8.5 million in the amortization
11	of the PERC Regulatory Asset as shown in column (l) on line 22.
12	
13	The Total PERC Expense for the projected test period is forecasted at \$22.8 million
14	as shown in column (n) on line 23. The derivation of this Total PERC Expense is
15	shown on Exhibit A-13, Schedule C5.17 and is sponsored by Witness Uzenski; I
16	detail the projects comprising line 2 of Exhibit A-13, Schedule C5.17 in Exhibit A-
17	13, Schedule C5.16, page 1.
18	
19	Q106. Can you explain the Total PERC O&M Expenditures detailed in Exhibit A-13,
20	Schedule C5.16, page 1?
21	A106. This exhibit shows the by-project PERC O&M expenditures for the 2021 historical
22	period and projected Calendar Years 2022, 2023 and 2024 planned expenditures
23	totaling \$15.1 million, \$18.6 million, \$14.4 million and \$24.5 million respectively.
24	

1	Q107. How do the Total PERC O&M Expenditures on line 27 of Exhibit A-13,
2	Schedule C5.16, page 1 relate to Exhibit A-13, Schedule C5.17?
3	A107. As an example, the actual total PERC O&M expenditures of approximately \$18.6
4	million for Calendar Year 2022 shown in Exhibit A-13, Schedule C5.16, page 1,
5	line 27, column (c) flows to Exhibit A-13, Schedule C5.17, page 1, line 2, column
6	(d).
7	
8	Q108. How does the PERC amortization expense on line 14 of Exhibit A-13, Schedule
9	C5.17, page 1 relate to Exhibit A-13, Schedule C5.3, page 1?
10	A108. Exhibit A-13, Schedule C5.17 shows the calculation for PERC amortization that
11	was derived from Exhibit A-13, Schedule C5.16, Page 1. Exhibit A-13, Schedule
12	C5.17, page 1, line 14, column (g) shows \$7.8 million as the calculated amortized
13	portion of PERC O&M for the 12-month test period ending November 30, 2024.
14	This \$7.8 million is used in Exhibit A-13, Schedule C5.3, page 1, line 22, column
15	(n).
16	
17	Q109. What was the rationale for the 24-Month Operating Cycle project shown on
18	line 3 of A-13, Schedule C5.16, page 1?
19	A109. The 24-month operating cycle project reduces the frequency of Fermi 2 refueling
20	outages and improves operating time. Operating on a 24-month cycle results in three
21	refueling outages every six years; operating on an 18-month operating cycle results
22	in four refueling outages every six years. Prior to the 24-month operating cycle
23	project, Fermi 2 previously operated with 18-month operating cycles; therefore,
24	transitioning to a 24-month operating cycle results in additional generation over a
25	six-year cycle due to fewer refueling outages.

1	
2	Fermi 2's cycle length is limited by our NRC license. The 24-Month Operating
3	Cycle project performed an analysis to ensure the plant could operate 24 months
4	between refueling outages and submitted that analysis as a license amendment
5	request to the NRC to update the Fermi 2 license to allow a 24-month cycle. DTE
6	Electric received NRC approval in early 2021 and began its first 24-month operating
7	cycle in 2022 upon exiting RF21.
8	
9	The Company first introduced the 24-Month Operating Cycle project in Case No.
10	U-20162. The Commission responded favorably and approved cost recovery
11	associated with the 24-Month Operating Cycle project in the Case No. U-20162
12	Order dated May 2, 2019.
13	
13 14	Q110. What are the expenditures and the rationale for the Fermi 2 Nuclear Extended
13 14 15	Q110. What are the expenditures and the rationale for the Fermi 2 Nuclear Extended Power Uprate (EPU) Study project shown on line 18 of Exhibit A-13, Schedule
13 14 15 16	Q110. What are the expenditures and the rationale for the Fermi 2 Nuclear Extended Power Uprate (EPU) Study project shown on line 18 of Exhibit A-13, Schedule C5.16, page 1?
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> </ol>	<ul> <li>Q110. What are the expenditures and the rationale for the Fermi 2 Nuclear Extended</li> <li>Power Uprate (EPU) Study project shown on line 18 of Exhibit A-13, Schedule</li> <li>C5.16, page 1?</li> <li>A110. The Fermi 2 Extended Power Uprate (EPU) Study project is to provide a detailed</li> </ul>
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> </ol>	<ul> <li>Q110. What are the expenditures and the rationale for the Fermi 2 Nuclear Extended Power Uprate (EPU) Study project shown on line 18 of Exhibit A-13, Schedule C5.16, page 1?</li> <li>A110. The Fermi 2 Extended Power Uprate (EPU) Study project is to provide a detailed feasibility, scoping and estimating analysis, regarding the potential for Fermi 2 to</li> </ul>
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> </ol>	<ul> <li>Q110. What are the expenditures and the rationale for the Fermi 2 Nuclear Extended Power Uprate (EPU) Study project shown on line 18 of Exhibit A-13, Schedule C5.16, page 1?</li> <li>A110. The Fermi 2 Extended Power Uprate (EPU) Study project is to provide a detailed feasibility, scoping and estimating analysis, regarding the potential for Fermi 2 to support an EPU. The Fermi 2 EPU Study project actual expenditures in Calendar</li> </ul>
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> </ol>	<ul> <li>Q110. What are the expenditures and the rationale for the Fermi 2 Nuclear Extended Power Uprate (EPU) Study project shown on line 18 of Exhibit A-13, Schedule C5.16, page 1?</li> <li>A110. The Fermi 2 Extended Power Uprate (EPU) Study project is to provide a detailed feasibility, scoping and estimating analysis, regarding the potential for Fermi 2 to support an EPU. The Fermi 2 EPU Study project actual expenditures in Calendar Year 2021 are \$0.0 million and the Fermi 2 EPU Study project projected</li> </ul>
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> </ol>	<ul> <li>Q110. What are the expenditures and the rationale for the Fermi 2 Nuclear Extended Power Uprate (EPU) Study project shown on line 18 of Exhibit A-13, Schedule C5.16, page 1?</li> <li>A110. The Fermi 2 Extended Power Uprate (EPU) Study project is to provide a detailed feasibility, scoping and estimating analysis, regarding the potential for Fermi 2 to support an EPU. The Fermi 2 EPU Study project actual expenditures in Calendar Year 2021 are \$0.0 million and the Fermi 2 EPU Study project projected expenditures in forecasted Calendar Years 2022, 2023 and 2024 are \$0.0 million,</li> </ul>
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> </ol>	<ul> <li>Q110. What are the expenditures and the rationale for the Fermi 2 Nuclear Extended Power Uprate (EPU) Study project shown on line 18 of Exhibit A-13, Schedule C5.16, page 1?</li> <li>A110. The Fermi 2 Extended Power Uprate (EPU) Study project is to provide a detailed feasibility, scoping and estimating analysis, regarding the potential for Fermi 2 to support an EPU. The Fermi 2 EPU Study project actual expenditures in Calendar Year 2021 are \$0.0 million and the Fermi 2 EPU Study project projected expenditures in forecasted Calendar Years 2022, 2023 and 2024 are \$0.0 million, \$4.9 million and \$0.0 million respectively as shown on line 18 of Exhibit A-13,</li> </ul>
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>23</li> </ol>	<ul> <li>Q110. What are the expenditures and the rationale for the Fermi 2 Nuclear Extended Power Uprate (EPU) Study project shown on line 18 of Exhibit A-13, Schedule C5.16, page 1?</li> <li>A110. The Fermi 2 Extended Power Uprate (EPU) Study project is to provide a detailed feasibility, scoping and estimating analysis, regarding the potential for Fermi 2 to support an EPU. The Fermi 2 EPU Study project actual expenditures in Calendar Year 2021 are \$0.0 million and the Fermi 2 EPU Study project projected expenditures in forecasted Calendar Years 2022, 2023 and 2024 are \$0.0 million, \$4.9 million and \$0.0 million respectively as shown on line 18 of Exhibit A-13, Schedule C5.16, page 1; Fermi 2 EPU Study project expenditures would also occur</li> </ul>
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>23</li> <li>24</li> </ol>	<ul> <li>Q110. What are the expenditures and the rationale for the Fermi 2 Nuclear Extended Power Uprate (EPU) Study project shown on line 18 of Exhibit A-13, Schedule C5.16, page 1?</li> <li>A110. The Fermi 2 Extended Power Uprate (EPU) Study project is to provide a detailed feasibility, scoping and estimating analysis, regarding the potential for Fermi 2 to support an EPU. The Fermi 2 EPU Study project actual expenditures in Calendar Year 2021 are \$0.0 million and the Fermi 2 EPU Study project projected expenditures in forecasted Calendar Years 2022, 2023 and 2024 are \$0.0 million, \$4.9 million and \$0.0 million respectively as shown on line 18 of Exhibit A-13, Schedule C5.16, page 1; Fermi 2 EPU Study project expenditures would also occur beyond the test period in 2025 and 2026 to support analysis of certain equipment</li> </ul>

# 2 **Q111. What is an EPU?**

3 A111. U.S. Commercial reactors, such as Fermi 2, were designed with excess capacity that 4 would allow for a potential uprate; however, the NRC licenses for commercial 5 nuclear power plants establishes limits on the maximum heat output, or power level, 6 for the reactor core; this power level plays an important role in many of the analyses 7 that demonstrate plant safety, so the NRC's permission is required before a plant can 8 change its maximum power level. The NRC has approved EPU increases as high as 9 20 percent; however, EPUs usually require significant modifications to major pieces 10 of non-nuclear equipment such as turbines, main generators, pumps and motors, 11 transformers and steam dryers.

12

Line

No.

1

# Q112. What would be the potential benefit of performing an EPU at the Fermi 2 Power Plant?

A112. Performing an EPU at the Fermi 2 Power Plant could yield an additional 172 MWe
 of carbon-free, resilient, baseload generation capacity for Michigan. The only
 variable O&M cost associated with this additional 172 MWe is the cost of nuclear
 fuel, which could result in significant Power Supply Cost Recovery (PSCR) savings
 for DTE Electric customers.

20

# Q113. Are EPU capital expenditures eligible for production tax credits as enacted by the Inflation Reduction Act of 2022 (IRA)?

A113. Maybe. By enacting the IRA, the U.S. Congress intended to incentivize incremental
 carbon-free generation from both new carbon-free electricity generation units as
 well as at carbon-free electricity generators that were operating prior to 2025;

2

3

however, DTE Electric, and indeed the entire U.S. commercial nuclear industry, requires additional guidance from the U.S. Internal Revenue Service (IRS) prescribing how the IRS intends to regulate potential existing nuclear fleet EPU capacity improvements with regard to the IRA.

5

4

#### 6 Q114. What would be the potential benefit of performing the Fermi 2 EPU Study?

7 A114. An EPU project would be complex with considerable scope and cost unknowns; for 8 example, DTE Electric's level of effort analysis provides a total EPU cost ranging 9 between \$600 million and \$1,000 million with the largest drivers of cost uncertainty 10 being unknowns regarding the margins available within Fermi 2's existing 11 equipment such as the steam dryer, emergency equipment cooling system strainers, 12 turbine valves, main steam lines and main unit generator to operate safely at EPU 13 conditions or if the existing equipment must be replaced to support EPU conditions. Performing the EPU Study project would allow DTE Electric to narrow the 14 15 uncertainty in scope and cost to support a reasonable and prudent decision for a 16 Fermi 2 EPU.

17

#### 18 Q115. What would be the deliverable of the Fermi 2 EPU Study?

A115. The Fermi 2 EPU Study project would perform a detailed analysis of Fermi 2's
existing equipment and determine the required actions to support Fermi 2 EPU
operations; analysis would recommend if existing equipment can support EPU
through additional engineering analysis or if existing equipment must be replaced.
The Fermi 2 EPU Study would support individual cost estimates for projects
required to harden or replace specific equipment as well as cumulative total EPU
costs. DTE Electric expects the study to take several years to complete, as equipment

Line No.	<b>J. C. DAVIS</b> U-21297
1	such as the steam dryer requires a refueling outage to access and instrument for
2	margin analysis. Once the study concludes in 2026, we will have a more certain
3	understanding of the scope and costs required to perform an EPU at Fermi 2 Power
4	Plant.
5	
6	Q116. What are the Total Nuclear Power Generation O&M expenses that you support
7	for the projected test period ending November 30, 2024?
8	A116. I support Total Nuclear Power Generation O&M expenses of \$177.0 million for the
9	projected test period as shown in Exhibit A-13, Schedule C5.3, page 1, line 24,
10	column (n). As I have discussed previously, these projected Total Operation and
11	Maintenance expenses are required for the safe and reliable operation of Fermi 2 for
12	the projected test period. I consider these expenses to be prudent and reasonable.
13	
14	Nuclear Surcharge
15	Q117. Is the Company requesting a change to the Nuclear Surcharge?
16	A117. Only with respect to inflation for the Site Security and Radiation Protection portion
17	of the Nuclear Surcharge. The Company is proposing an updated Nuclear Surcharge
18	based on the same approach approved by the Commission in Case Nos. U-17767,
19	U-18014, U-18255, U-20162, U-20561 and U-20836 and depicted in Exhibit A-20,
20	Schedule J1.
21	
22	The Site Security and Radiation Protection portion of the surcharge has been
23	updated to reflect 2021 historical expense adjusted for inflation on line 2. The
24	inflation rate is supported by Witness Uzenski on Exhibit A-13, Schedule C5.15.
25	

Line <u>No.</u>	<b>J. C. DAVIS</b> U-21297
1	The Nuclear Decommissioning Funding portion of the surcharge shown on line 3 is
2	unchanged.
3	
4	The Low Level Radioactive Waste (LLRW) Disposal Funding portion of the annual
5	surcharge shown on line 4 is unchanged.
6	
7	The resulting nuclear surcharge set forth in Company rates is supported by Company
8	Witness Willis on Exhibit A-16, Schedule F6.
9	
10	Q118. What is the Nuclear Surcharge that you support for the 12-month projected
11	test period ending November 30, 2024?
12	A118. I support the Proposed Nuclear Surcharge of \$38.9 million for the projected test
13	period as shown in Exhibit A-20, Schedule J1, page 1, line 5, column (b); this
14	represents a decrease of approximately \$0.2 million from the current authorized
15	Nuclear Surcharge shown on line 6, column (b). The Proposed Nuclear Surcharge
16	funds Fermi 2 site security, radiation protection, nuclear decommissioning and the
17	disposal of LLRW; these activities are required for safe and secure operation of the
18	Fermi 2 Power Plant for the projected test period. I consider the Proposed Nuclear
19	Surcharge to be prudent and reasonable.
20	
21	Q119. Does this complete your direct testimony?

A119. Yes, it does.

### STATE OF MICHIGAN

## BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)
DTE ELECTRIC COMPANY	)
for authority to increase its rates, amend	)
its rate schedules and rules governing the	)
distribution and supply of electric energy, and	)
for miscellaneous accounting authority.	)

Case No. U-21297

### QUALIFICATIONS

### AND

#### DIRECT TESTIMONY

OF

#### SATVIR S. DEOL

## DTE ELECTRIC COMPANY QUALIFICATIONS AND DIRECT TESTIMONY OF SATVIR S. DEOL

Line <u>No.</u>

1	Q1.	What is your name, business address and by whom are you employed?
2	A1.	My name is Satvir S. Deol (he/him/his), and my business address is One Energy
3		Plaza, Detroit, Michigan, 48226 and I am employed by DTE Electric Company
4		(DTE Electric or Company).
5		
6	Q2.	On whose behalf are you testifying?
7	A2.	I am testifying on behalf of DTE Electric.
8		
9	Q3.	What is your educational background?
10	A3.	I received a Bachelor of Science Degree in Electrical Engineering specializing in
11		Power Distribution from Michigan Technological University. I graduated from
12		University of Minnesota with a Master of Science in Electrical Engineering
13		specializing in Power System Control. I also have a Master of Business
14		Administration specializing in Finance from University of Michigan – Dearborn.
15		Furthermore, I have attended professional development courses in power system
16		design & protection and circuit modeling & power flow analysis. I was also trained
17		in the Toyota Production System (TPS) continuous improvement methodologies.
18		
19	Q4.	Please summarize your professional experience.
20	A4.	I worked for Shell Western Exploration & Production, Inc. (SWEPI) as a facilities
21		engineer from 1990 to 1992. I was responsible for coordinating & performing
22		maintenance on substations, co-generation facilities, and the power distribution
23		network for all oil production fields and offshore platforms in California. I also
24		supported the field electrical teams for emergent issues and was the project manager

25 for several major electrical projects.

Line
No.

1	I worked for Ford Motor Company (Ford) from 1995 to 2007. Through my twelve
2	year career at Ford, I had numerous assignments with increasing responsibility. As
3	a product design engineer, I designed electrical motors and received two patents. I
4	have experience in the production and assembly of electrical components as a
5	manufacturing engineer. I have worked internationally, launching an alternator
6	rectifier assembly line in India, and upgrading a plant in Brazil. As a product
7	planning analyst, I worked with hybrid, electrical & fuel cell vehicle architectures
8	and gained experience working within industry consortiums. I obtained leadership
9	experience as a powertrain capacity planning supervisor and then as an ignition
10	system supervisor, where I had design & release responsibility of all current and
11	future ignition systems for all North America produced V-engines. Also, I achieved
12	my six-sigma black belt certification and led numerous continuous improvement
13	projects.

I joined DTE Energy in 2007 as a program manager to implement continuous
 improvement programs within the Materials & Logistics organization. After a
 series of roles with increasing responsibility, in 2010 I was promoted to senior
 supply chain manager supporting Fossil Generation Operations.

19

In 2013, I moved to Distribution Operations as a program leader for a continuous improvement project focusing on the oil distribution breaker inspection process. In 2014, I assumed the role as a service center manager leading the Southwest region for Substation Operations. In this role, I was responsible for the operation, planned & corrective maintenance, and executing capital projects for substations in my

Line <u>No.</u>		
1		region. I was given the additional responsibility of the Southeast region in 2016.
2		In 2018, I was promoted to my current role as director of Substation Operations.
3		
4	Q5.	Do you hold any certifications or are you a member of any professional
5		organizations?
6	A5.	I am a Lean Six Sigma Blackbelt.
7		
8	Q6.	What are your current duties and responsibilities?
9	A6.	As director of Substation Operations, I am responsible to ensure safe and reliable
10		operation of all the substations within the DTE Energy service territory. The major
11		areas of focus are: 1) safety; 2) planned maintenance; 3) emergent & corrective
12		maintenance; 4) capital replacement programs; and 5) continuous improvement.
13		
14	Q7.	Have you previously sponsored testimony before the Michigan Public Service
15		Commission (MPSC or Commission)?
16	A7.	I have not testified before the Michigan Public Service Commission.

### 1 **Purpose of Testimony**

2	Q8.	What is the j	purpose of you	ur testimony?			
3	A8.	As referenced in witness Robinson's description of the distribution witnesses, the					
4		purpose of m	ny testimony is	s to support, as reasonable and prudent, the historical			
5		capital expen	capital expenditures for 2021 and projected capital expenditures for 2022 thru				
6		November 3	30, 2024, in	the distribution strategic investment category of			
7		Infrastructure	e Redesign an	d Modernization and discuss metrics and programs			
8		associated w	ith the Comp	any's proposed Infrastructure Recovery Mechanism			
9		(IRM).					
10							
11	Q9.	Are you spor	nsoring any ex	whibits in this proceeding?			
12	A9.	Yes. I am sp	onsoring the fo	ollowing exhibits:			
13		<u>Exhibit</u>	<u>Schedule</u>	Description			
14		A-12	B5.4	Projected Capital Expenditures – Distribution Plan			
15				(Pages 1, 2, 9-11, and 13-21)			
16		A-23	M5	Distribution Plant Capital Project Detail –			
17				Infrastructure Redesign and Modernization			
18		A-23	M10	Appoline Report			
19		A-33	X2	Distribution – Base Rate Investments +			
20				Infrastructure Recovery Mechanism			
21		A-33	X3	Distribution - Infrastructure Recovery Mechanism			
22							
23	Q10.	Were these e	exhibits prepa	red by you or under your direction?			
24	A10.	Yes, they we	re.				
25							

10.			
1	Q11.	How is your	testimony organized?
2	A11.	My testimon	y consists of the following parts:
3		Part I	Infrastructure Recovery Mechanism (IRM) Support
4		Part II	Infrastructure Redesign and Modernization
5			
6	<u>Part I</u>	Infrastructu	re Recovery Mechanism (IRM) Support
7	Q12.	Is the Comp	pany proposing that any of the capital programs discussed in your
8		testimony	and exhibits be associated with the Company's proposed
9		Distribution	n Infrastructure Recovery Mechanism (IRM)?
10	A12.	Yes. As par	rt of the IRM proposal put forth by Company witness Foley, the
11		Company is	proposing that a portion of Conversions program investment and a
12		portion of Su	ubtransmission Redesign & Rebuild program investment be authorized
13		for IRM trea	tment.
14			
15	Q13.	Why does th	ne Company believe that it is appropriate for these programs to be
16		authorized	for IRM treatment?
17	A13.	These progra	ams are appropriate for the Distribution IRM because they are a key
18		focus of and	d requirement for the Company's future grid plan. Inclusion will
19		provide supp	port for the incorporation of new technologies such as electric vehicle
20		(EV) chargi	ng stations and Distributed Energy Resources (DERs), as well as
21		operational t	technologies. As described below in more detail, these programs are
22		designed to	improve reliability, operability, and safety, as well as add capacity to
23		the Compan	y's system. In previous rate cases the Commission has expressed
24		concern as to	the Company's ability to achieve projected investment levels in these
25		programs. A	as further described by Company witness Foley, inclusion of these

### Line <u>No.</u>

programs in the Distribution IRM will help ensure that the Company invests in
 programs that are a priority for customers while also ensuring that customers do not
 fund investments that do not occur.

4

# 5 Q14. What level of investment is the Company proposing that the Commission 6 authorize under the Distribution IRM for these programs?

A14. As discussed by Company witness Foley, the Company is proposing a roughly 3year IRM beginning concurrent with the projected test year in the instant case (i.e.,
December 1, 2023). The Company is proposing that IRM Plan Year 1 be 13 months
such that subsequent IRM plan years are aligned to calendar years. As captured in
witness Foley's Exhibit A-33, Schedule X1, I am proposing the following
investment level shown in Table 1 for the programs I am supporting in the instant
case.



Table 1	Distribution	IRM	Investments	(\$millions)
---------	--------------	-----	-------------	--------------

	Projected Test Year	Plan Year 1	Plan Year 2	Plan Year 3
Capital Program	(12 mos. end 11/30/24)	13 mos. ending 12/31/2024	12 mos. ending 12/31/2025	12 mos. ending 12/31/2026
Conversions	\$371.6	\$1.6	\$185.8	\$371.6
Subtransmission Redesign & Rebuild	\$107.6	\$5.5	\$53.8	\$107.6

As described by Company witness Foley, if the Company were to invest less than

15

16

these levels, the associated over-recovery of costs would be refunded to customers.
The level of Distribution IRM Investments for the projected test year (12 months
ending 11/30/24) is supported on Exhibit A-33, Schedules X2 and X3, sponsored SSD-6

by Company Witnesses Hill, Elliott Andahazy, and myself. Schedule X2 1 2 distinguishes expenditures included in the base rate request from the amounts 3 included in the IRM request, while Schedule X3 details the IRM investments in 4 detail by project. 5 For the Conversions and Subtransmission Redesign & Rebuild programs, I am 6 7 sponsoring an investment level of \$1.5 million and \$5.1 million, respectively, for 8 12 months ending 11/30/2024 on Exhibit A-33, Schedule X3, Lines 8 and 28. 9 10 These amounts are also shown on Exhibit A-33, Schedule X2, lines 4 and 5, column 11 (c), as part of the IRM expenditures and relate only to new projects starting in the 12 projected test period. Capital expenditures related to projects already underway 13 prior to the projected test period remain in the base rate request on line 4 and 5, 14 column (b). All other Infrastructure Redesign and Modernization expenditures 15 remain in the base rate request as shown on line 6, column (b). The grand total in 16 column (d) for the Conversions program on line 5 in the amount of \$371.6 million 17 as well as the Subtransmission Redesign & Rebuild program on line 6 in the amount 18 of \$107.6 million is used by witness Foley to increase the level of IRM investment 19 in IRM Year 2 (50% of the total spend) and IRM Year 3 (100% of the total spend) 20 as shown in Table 1 above. 21 22 Q15. What does the Company intend to accomplish for these programs during the 23 **IRM timeframe?** 24 A15. These programs are a key focus for the Company's grid of the future. Through the 25 conversion projects, the Company expects to see an 85% reduction in customer

Line
<u>No.</u>

wire downs, conversion. capacity to etailed later
conversion. capacity to etailed later
l capacity to etailed later
etailed later
etailed later
cuits on the
tionally, the
ot currently
ı its limited
ion program
s is provided
g the IRM
eds (safety,
thod (GPM)
ion metrics
any witness
any witness in Table 2.

Programs	<b>Program Execution Metric*</b>		
	OH line miles converted		
	Average cost per OH line mile converted		
	UG line miles converted		
Conversions	Average cost per UG line mile converted		
Conversions	Higher Voltage substations constructed		
	Average Cost per substation constructed		
	4.8kV substations decommissioned		
	Average cost per 4.8kV substation decommissioned		
	OH line miles		
	Average cost per OH line mile		
Subtransmission	UG line miles		
Redesign & Rebuild	Average cost per UG line miles		
	Stations constructed/rebuilt		
	Average cost per stations constructed/rebuilt		

Table 2IRM Program Execution Metrics

\* measured vs. target

2

#### 3 Q18. What are the benefits of IRM treatment for the proposed capital programs?

# 4 A18. As further discussed by Company witness Foley, there are four key benefits of a 5 Distribution IRM:

Certainty of investment. The approval of an IRM effectively establishes a
dedicated funding source for capital programs critical to customer safety,
reliability, and/or resiliency. The Company would not be able to shift investment
authorized for IRM treatment to programs outside the IRM, or between
programs within it. Importantly, any underinvestment in the programs associated
with IRM would be returned to customers.

Greater transparency. As part of the Distribution IRM, new planning and
 reconciliation process would be established that would provide Staff with

1

<u>No.</u>		
1		greater transparency into the Company's investment plans and its execution of
2		those plans.
3		- Opportunities for feedback. As part of the IRM Planning Process, Staff would
4		have the opportunity to review and provide feedback on the Company's planned
5		IRM investments for the upcoming year. Likewise, the Company would then
6		have the opportunity to address that feedback and respond to any questions or
7		concerns raised by Staff before execution of its plans.
8		- Increased accountability. As part of the IRM Reconciliation process, the
9		Company would begin reporting new program execution metrics to help assess
10		its execution of its investment plans.
11		
12	<u>Part I</u>	I Infrastructure Redesign and Modernization
13	Q19.	What is included in Infrastructure Redesign and Modernization?
13 14	<b>Q19.</b> A19.	What is included in Infrastructure Redesign and Modernization?As discussed by company witness Miller, projects and programs in the
13 14 15	<b>Q19.</b> A19.	What is included in Infrastructure Redesign and Modernization?As discussed by company witness Miller, projects and programs in theInfrastructure Redesign and Modernization pillar fundamentally upgrade the
13 14 15 16	<b>Q19.</b> A19.	What is included in Infrastructure Redesign and Modernization? As discussed by company witness Miller, projects and programs in the Infrastructure Redesign and Modernization pillar fundamentally upgrade the electrical system. Projects fall into three primary areas, Subtransmission Redesign
13 14 15 16 17	<b>Q19.</b> A19.	What is included in Infrastructure Redesign and Modernization?As discussed by company witness Miller, projects and programs in theInfrastructure Redesign and Modernization pillar fundamentally upgrade theelectrical system. Projects fall into three primary areas, Subtransmission Redesign& Rebuild, Conversion to higher voltage (City of Detroit Infrastructure (CODI) and
13 14 15 16 17 18	<b>Q19.</b> A19.	What is included in Infrastructure Redesign and Modernization? As discussed by company witness Miller, projects and programs in the Infrastructure Redesign and Modernization pillar fundamentally upgrade the electrical system. Projects fall into three primary areas, Subtransmission Redesign & Rebuild, Conversion to higher voltage (City of Detroit Infrastructure (CODI) and Conversions), and System Loading. Voltage and purpose distinguish the difference
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> </ol>	<b>Q19.</b> A19.	What is included in Infrastructure Redesign and Modernization? As discussed by company witness Miller, projects and programs in the Infrastructure Redesign and Modernization pillar fundamentally upgrade the electrical system. Projects fall into three primary areas, Subtransmission Redesign & Rebuild, Conversion to higher voltage (City of Detroit Infrastructure (CODI) and Conversions), and System Loading. Voltage and purpose distinguish the difference between the Company's subtransmission system and distribution system. The
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> </ol>	<b>Q19.</b> A19.	What is included in Infrastructure Redesign and Modernization? As discussed by company witness Miller, projects and programs in the Infrastructure Redesign and Modernization pillar fundamentally upgrade the electrical system. Projects fall into three primary areas, Subtransmission Redesign & Rebuild, Conversion to higher voltage (City of Detroit Infrastructure (CODI) and Conversions), and System Loading. Voltage and purpose distinguish the difference between the Company's subtransmission system and distribution system. The Company operates subtransmission voltages of 24kV, 40kV, and 120kV and this
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> </ol>	<b>Q19.</b> A19.	What is included in Infrastructure Redesign and Modernization? As discussed by company witness Miller, projects and programs in the Infrastructure Redesign and Modernization pillar fundamentally upgrade the electrical system. Projects fall into three primary areas, Subtransmission Redesign & Rebuild, Conversion to higher voltage (City of Detroit Infrastructure (CODI) and Conversions), and System Loading. Voltage and purpose distinguish the difference between the Company's subtransmission system and distribution system. The Company operates subtransmission voltages of 24kV, 40kV, and 120kV and this infrastructure is designed to feed substations that convert the voltage to distribution
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> </ol>	<b>Q19.</b> A19.	What is included in Infrastructure Redesign and Modernization? As discussed by company witness Miller, projects and programs in the Infrastructure Redesign and Modernization pillar fundamentally upgrade the electrical system. Projects fall into three primary areas, Subtransmission Redesign & Rebuild, Conversion to higher voltage (City of Detroit Infrastructure (CODI) and Conversions), and System Loading. Voltage and purpose distinguish the difference between the Company's subtransmission system and distribution system. The Company operates subtransmission voltages of 24kV, 40kV, and 120kV and this infrastructure is designed to feed substations that convert the voltage to distribution levels. The Company currently operates distribution voltages of 4.8kV, 8.3kV, and
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>23</li> </ol>	<b>Q19.</b> A19.	What is included in Infrastructure Redesign and Modernization? As discussed by company witness Miller, projects and programs in the Infrastructure Redesign and Modernization pillar fundamentally upgrade the electrical system. Projects fall into three primary areas, Subtransmission Redesign & Rebuild, Conversion to higher voltage (City of Detroit Infrastructure (CODI) and Conversions), and System Loading. Voltage and purpose distinguish the difference between the Company's subtransmission system and distribution system. The Company operates subtransmission voltages of 24kV, 40kV, and 120kV and this infrastructure is designed to feed substations that convert the voltage to distribution levels. The Company currently operates distribution voltages of 4.8kV, 8.3kV, and 13.2kV and this infrastructure is designed to feed customers. Subtransmission
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>23</li> <li>24</li> </ol>	<b>Q19.</b> A19.	What is included in Infrastructure Redesign and Modernization? As discussed by company witness Miller, projects and programs in the Infrastructure Redesign and Modernization pillar fundamentally upgrade the electrical system. Projects fall into three primary areas, Subtransmission Redesign & Rebuild, Conversion to higher voltage (City of Detroit Infrastructure (CODI) and Conversions), and System Loading. Voltage and purpose distinguish the difference between the Company's subtransmission system and distribution system. The Company operates subtransmission voltages of 24kV, 40kV, and 120kV and this infrastructure is designed to feed substations that convert the voltage to distribution levels. The Company currently operates distribution voltages of 4.8kV, 8.3kV, and 13.2kV and this infrastructure is designed to feed customers. Subtransmission projects focus on the subtransmission system, whereas conversion and load relief

Line

1		Infrastructure Redesign and Modernization projects are included in Exhibit A-12,
2		Schedule B5.4, pages 910 and Exhibit A-23, Schedule M5. Also included on
3		Exhibit A-12, Schedule B5.4 for this category is AFUDC on page 13 and plant
4		activity on pages 15-19, described in more detail by Company Witness Miller
5		
6	Q20.	Why are Infrastructure Redesign and Modernization Projects needed?
7	A20.	Infrastructure Redesign and Modernization projects are a key part of the
8		Company's plan for the grid of the future. These projects add capacity by
9		converting to a higher voltage for growing customer load, reduces outages and
10		outage restoration time using modern equipment, improves redundancy and
11		resiliency of the system, and increases safety. Projects in this pillar fundamentally
12		change the way the grid operates. For these reasons, detailed in more depth later in
13		my testimony, the Company is increasing focus on these projects and accelerating
14		the rate at which it implements conversions, subtransmission rebuilds, and load
15		relief projects.
16		
17	Q21.	Are there specific Infrastructure Redesign and Modernization programs you
18		would like to discuss in more detail?
19	A21.	Yes. I would like to highlight the following programs because I believe that
20		discussion beyond what is contained in the exhibits will be helpful in establishing
21		a deeper understanding of their scope, the rationale for making the investments, and
22		the benefits customers will receive:
23		• 4.8kV Conversion
24		<ul> <li>4.8kV ISO Conversion Program</li> </ul>
25		• City of Detroit Infrastructure (CODI)

Line <u>No.</u>		U-21297
1		• 8.3kV CC: Pontiac Conversion
2		Subtransmission Redesign & Rebuild
3		Strategic Undergrounding Projects
4		Primary Deconductoring
5		System Loading
6		
7	2	4.8kV Conversion
8	Q22.	Can you describe the Company's 4.8kV distribution system?
9	A22.	The Company's original distribution system voltage is 4.8kV. The system was
10		designed to an ungrounded delta configuration and banked secondary standard,
11		which has both benefits and drawbacks. Delta configuration is a design from the
12		early 1900's, which for many years provided very low number of outages. In most
13		neighborhoods, the 4.8kV system was constructed as OH rear-lot poles and wires,
14		which customers find aesthetically preferable to front-lot construction. Initially,
15		right-of-way truck access was readily available through municipally maintained
16		alleys in many areas, including much of Detroit. Starting in the mid-1950's, many
17		municipalities began to abandon alleys and allowed property owners to extend their
18		fence lines, inhibiting Company truck access to the poles and wires. Consequently,
19		the limited access resulted in a significant increase in the time to locate and repair
20		trouble on the 4.8kV system, as well as increases in time to perform tree trimming
21		and other maintenance work.
22		
23	Q23.	What are the challenges and issues associated with the 4.8kV system?
24	A23.	Beside accessibility, other key issues impacting the reliability and operability of the

25 Company's 4.8kV system are summarized below:

### SSD-12

<b>S. S. DEC</b> U-212	<b>)L</b> 97
• The 4.8kV system uses the small #6 and #4 conductors, which are weaker	: in
strength compared to current higher standard wires.	
• Inherent in the design, the 4.8kV substations and circuits have lower capac	ity
than the higher voltage systems.	
• The 4.8kV system can experience more significant voltage drops than high	her
voltage systems.	
• The 4.8kV system is an ungrounded delta configuration, making detection	on,
location, and protection of single-phase downed wires challenging.	
• Ringed circuit and banked secondary designs make maintenance, fa	ult
identification, troubleshooting, and restoration more difficult and can res	ult
in outages that are longer in duration. Opening the rings on 4.8kV circu	iits
may result in low voltage and/or more outage events for customers.	
• The 4.8kV system is less compatible with today's automated technology	
• The 4.8kV system has a limited amount of remote monitoring and contra	rol
capability. Due to equipment age, the retrofits on 4.8kV substations a	ınd
circuits to enhance remote monitoring and control capability are costly a	ınd
challenging. The original 4.8kV substation design included individual rela	iys
for individual functions, usually on a 3-foot-by-7-foot panel. When a new	ew
breaker is installed, the entire relay panel and all associated control wiri	ing
must be replaced to accommodate the new technology.	
Q24. Why does the Company need to convert its 4.8kV system?	
A24. The conversion program has several customer benefits: it will allow t	the
decommissioning of aging equipment, which will lead to improved reliability a	ınd
lower emergent maintenance costs; restoration times and costs will be reduced,	as

1	modern distribution equipment can, in the event of an outage, transfer loads
2	automatically, while substation and distribution equipment can be remotely
3	operated from the System Operation Center (SOC), eliminating the need to dispatch
4	operators or line crews to perform switching activities. The Company expects to
5	see an 85% reduction in customer minutes interruptions and customer interruptions,
6	a 90% reduction in wire downs, and an 85% reduction in trouble events.
7	Both 4.8kV and higher voltage systems are capable of handling additional load
8	from electric vehicles (EVs) and DERs. However, areas where the 4.8kV system is
9	near load capacity, adding these new technologies can quickly exceed system
10	capability. Conversion to higher voltages introduces more system capacity to
11	handle future electrification by increasing conductor size and reducing voltage
12	drop. Conversion will also allow for the adoption of modern automated technology,
13	to reduce outages and improve restoration time.

# Q25. What impact will the 4.8kV Hardening program have on the pace of conversion of the 4.8kV system?

A25. The 4.8kV Hardening program will not delay the pace of conversion. The 4.8kV
Hardening program is described in detail by witness Elliott Andahazy.

19

#### 20 Q26. What is the scope of the 4.8kV Conversion program?

A26. The program is aimed at upgrading the 4.8kV system to a higher voltage by building
new substations and upgrading circuits to add capacity to serve growing load. The
4.8 kV Conversion program also addresses deteriorating reliability performance
due to aging electric infrastructure. The work performed as part of a 4.8kV
Conversion includes:

		S. S. DEOL
Line <u>No.</u>		U-21297
1		• Remove arc wire from the Company's system,
2		• Building new higher voltage substations or expanding and upgrading
3		existing 13.2kV substations.
4		• Installing controls and automation in the substations and circuits to our latest
5		design standards.
6		• Completing overhead (OH) conversion work including rebuilding pole top
7		equipment, replacing poles and transformers as needed, and installing
8		neutral wire.
9		• Rebuilding underground infrastructure as needed.
10		• Reconductoring OH lines as needed based on new circuit configurations and
11		existing wire size.
12		• Establishing new distribution circuits from new, upgraded, or existing
13		13.2kV substations.
14		• Reconfiguring circuits and establishing new jumpering points (jumpering is
15		the act of feeding a circuit that has become deenergized with an adjacent
16		circuit, restoring power to the customers on the deenergized circuit).
17		• Converting and transferring the load off of the 4.8kV substations to the
18		higher voltage substations.
19		• Decommissioning of aging 4.8kV substations and associated
20		subtransmission infrastructure
21		
22	Q27.	Will customers benefit from overhead (OH) conversion work prior to building
23		a new higher voltage substation or in parallel with substation construction?
24	A27.	Yes. Projects where OH conversion work is performed early or in parallel with the
25		substation construction, the customers will see the reliability benefits sooner and a

		S. S. DEOL
Line <u>No.</u>		U-21297
1		reduction in wire downs. Once the substation is built, the added benefits of capacity
2		will be achieved as the circuits are energized to the higher voltage.
3		
4	Q28.	How are conversion projects prioritized?
5	A28.	The near term (five-year) projects reflect investments that address current loading
6		constraints and safety considerations on the system. The Company's engineers
7		consider substation firm rating, circuit overloads, wire downs per OH mile, and
8		substation risk, to define these investment projects.
9		
10		Prioritization and sequencing of a long-term conversion plan will be an iterative
11		process. Future iterations will include integrated forecasting tools that will enhance
12		planning capabilities and incorporate additional data, such as propensity studies and
13		hourly load shapes, into the current substation loading profiles. In addition, the pace
14		at which the electrification scenario develops, and the signposts of that scenario
15		materialize, will further impact results. More detail is provided in Exhibit A-23
16		Schedule M7 DGP, section 11.3.2 4.8kV Conversion prioritization.
17		
18	Q29.	Are there specific 4.8kV Conversion projects you would like to discuss in more
19		detail?
20	A29.	Yes. I would like to highlight the following projects because I believe that
21		discussion beyond what is contained in the exhibits will be helpful in establishing
22		a deeper understanding of their scope, of the rationale for making the investments,
23		and of the benefits customers will receive, as well as provide for a better
24		understanding of the drivers and benefits of 4.8kV conversion in general:
25		• I-94 Substation and Circuit Conversion (Promenade)

# SSD-16

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1

#### • Lapeer – Elba Expansion and Circuit Conversion (Apollo)

2

# 3 Q30. What are the benefits of the I-94 Substation and Circuit Conversion 4 (Promenade) project?

5 A30. The I-94 Substation and Circuit Conversion (Promenade) project provides 6 eliminates existing overloads and provides additional capacity to serve residential, 7 commercial, and industrial customers in the city of Detroit, southwest of Detroit 8 City Airport. The new 13.2kV Promenade substation will allow for the 9 decommissioning of existing 4.8kV substations Lambert, Lynch, and Pulford; all 10 of which are 70 years old or older. Decommissioning these substations will remove 11 at risk equipment, including 10 transformers, over 20 regulators, over 20 oil circuit 12 breakers and disconnects, over 20 miles of 4.8kV underground cable, and over 30 13 miles of 24kV underground cable. Conversion of the circuits will improve safety 14 and reliability for the customers in this area.

15

# Q31. What are the drivers, and scope of the I-94 Substation and Circuit Conversion (Promenade)?

A31. The Promenade project is driven by transmission system violations, future loading
 conditions, and aging infrastructure. Currently ITC has several MISO loading
 violations in the east downtown portion of their transmission system. The proposed
 future Saturn Promenade Islandview Alfred transmission system pathway will
 alleviate these violations.

An I-94 industrial park is expected to add new commercial and industrial customers to the area resulting in increased loads that the current system will not be able to adequately support. The Promenade project will also provide support for the

1		increased capacity demands that will result from the Detroit Public Lighting
2		Department (PLD) conversions. As customers are transferred from the old PLD
3		system to the Company's system, load on the Company's system has increased
4		causing overloads, creating planning criteria violations.
5		This project involves construction of the new 120kV to 13.2kV Promenade
6		substation and the conversion and transfer of 4.8kV circuits out of Lambert, Lynch,
7		and Pulford to the new Promenade substation. In total 23 4.8kV (10 Pulford circuits,
8		8 Lambert circuits, and 5 Lynch circuits) circuits will be converted to six 13.2kV
9		circuits. This will help allow for the decommissioning of Lambert, Lynch, and
10		Pulford substations. Additionally, the construction of the new 120kV transmission
11		feed will allow for the decommissioning of four 24kV trunk lines with an average
12		weighted age of 90 years.
13		
14	Q32.	What are the benefits of the Lapeer – Elba Expansion and Circuit Conversion
15		project?
16	A32.	The Lapeer - Elba project provides load relief and capacity for new growth in
17		Lapeer County. The decommissioning of Elba and Lapeer 4.8kV substations will
18		reduce outage risk by removing aging infrastructure from the system. New
19		jumpering capability will be established with the elimination of the 4.8kV islanded
20		system (an islanded system is an area where the 4.8kV system is surrounded by
21		13.2kV system). Additionally, reliability and power quality will be enhanced with
22		the upgraded distribution circuits and elimination of the 40kV OH infrastructure
23		feeding Elba.

# Q33. What are the drivers and scope of the Lapeer – Elba Expansion and Circuit Conversion project?

3 A33. Lapeer and Elba substations are both located in Lapeer County. The Lapeer 4 substation property has two substations, one operating at 4.8kV and the other at 5 13.2kV, while Elba is a 4.8kV substation. The Lapeer 4.8kV substation is 6 approaching its firm rating at summer peak, and the Elba substation exceeds its firm 7 rating, with its transformer over day-to-day rating at summer peak. The Lapeer 8 13.2kV substation is over firm rating, and one of its circuits is over day-to-day 9 rating, with the other approaching its day-to-day rating. Thus, the substation 10 capacity in the Lapeer-Elba area cannot accommodate any load growth. In addition 11 to the loading concerns, there are a number of reliability and operability issues in 12 the area. Elba substation is almost 70 years old and is fed from a 6-mile 40kV 13 dedicated OH line from Tie 9111 that has experienced poor reliability performance 14 due to its location in a heavily treed right-of-way with limited shutdown capability 15 for operation and maintenance. The 40kV problems have caused power quality 16 issues to customers served out of Elba. There is limited jumpering capability for 17 Elba, as it is an islanded 4.8kV area surrounded by 13.2kV substations.

18

19 The project involves construction of the new 120kV to 13.2kV Apollo substation 20 and the conversion and transfer of the 4.8kV circuits out of Lapeer and Elba to the 21 new Apollo substation. Following the transfer of all load, Elba Substation, the 22 40kV OH line feeding Elba, and the 4.8kV substation at Lapeer will be 23 decommissioned.

24

Line <u>No.</u>		<b>S. S. DEOL</b> U-21297
1		This project will reduce wire downs, improve reliability, and provide additional
2		capacity to serve new load and eliminate existing overloads.
3		
4	4	4.8kV ISO Conversion Program
5	Q34.	What is an ISO down?
6	A34.	The Company operates some circuits at 4.8kV that are fed from a 13.2kV
7		substation; these are known as isolation down areas (ISO down). The reason for
8		this grid configuration is that in some instances, there is a need to address
9		immediate overloading on a circuit or circuits fed from a substation at which other
10		circuits are not overloaded. This issue can be addressed by building a higher voltage
11		substation, typically 13.2kV, and converting only the overloaded circuits, or
12		portions of the circuit, to the higher voltage while operating the remaining circuits
13		at the current voltage, typically 4.8kV. Whereas all the circuits out of the new
14		substation are fed at 13.2kV, only the circuits that were overloaded operate at
15		13.2kV. Circuits that were not overloaded and rebuilt have the voltage dropped to
16		4.8kV by a transformer and operate unconverted as 4.8kV circuits, thus isolating
17		them from the 13.2kV circuits. Ultimately all the circuits will require conversion to
18		13.2kV as creating ISO downs is not a permanent solution because 4.8kV ISO
19		downed areas of the circuits have not been upgraded or modernized and have the
20		same characteristics of 4.8kV circuits fed from a 4.8kV substation: they have the
21		same reliability issues, safety concerns, and operational concerns, and face the same

- challenges when it comes to incorporating increasing EVs and DERs. Table 16
  provides the number of circuits with ISO downs, number of customers served, and
  the 4.8kV OH and underground line miles.
- 25

#### Line <u>No.</u>

1

#### Table 3Number of Circuits with ISO Downs

	Number of Circuits	Number of Customers	Miles Overhead Wire	Miles Underground Wire
4.8kV ISO Downs	433	143,504	5,559	398

3

#### 4 Q35. What are the benefits of the 4.8kV ISO Conversion program?

A35. The ISO conversion projects are expected to bring multiple benefits including
safety improvements by reducing wire downs; improving reliability; providing for
technology modernization; providing additional capacity; and avoiding costs
associated with aging infrastructure.

9

#### 10 Q36. What is the scope of work for converting ISO down areas?

A36. The program is aimed at upgrading the 4.8kV portions of the circuits to a higher
voltage, thus adding capacity to serve growing load, improve safety by reducing
wire downs, improve jumpering capability to adjacent 13.2kV circuits, and to
address deteriorating reliability performance due to aging electric infrastructure.
The scope of work for the 4.8kV ISO down conversions includes:

- Installing controls and automation in the substations and circuits to our latest
   design standards
- Completing OH conversion work including rebuilding pole tops, replacing
   poles and transformers as needed, and installing neutral wire.
- Rebuilding underground infrastructure as needed.

#### SSD-21

<sup>2</sup> 

Line No.		<b>S. S. DEOL</b> U-21297
1		• Reconductoring OH lines as needed based on new circuit configurations and
2		existing wire size.
3		• Reconfiguring circuits and establishing new jumpering points.
4		<ul> <li>Removing ISO down transformers.</li> </ul>
5		
6	Q37.	How will circuits in the 4.8kV ISO Conversion program be prioritized?
7	A37.	The Company prioritizes the order in which it addresses the different ISO down
8		locations based on specific criteria, with safety being the primary driver in the
9		prioritization efforts. Work is prioritized at the substation level, as it is more
10		efficient to plan and perform the work for the group of circuits tied to the same
11		substation. Each ISO down is scored based on the following factors:
12		1) Recorded wire downs;
13		2) Total substation SAIDI;
14		3) Total outage and non-outage events requiring the dispatch of a line crew.
15		
16		Ranking of the substations follows the Company's overall goals of reducing risk,
17		improving reliability, and managing costs. The Company calculates a three-year
18		historic average for wire downs, customer minutes interruption (SAIDI),
19		outage/non-outage events and estimates the amount of reduction ISO down
20		conversion is expected to bring in each metric like the calculations for the impact
21		dimensions in the GPM model as discussed by witness Kryscynski. The amount of
22		reduction in wire downs, SAIDI, and outage/non-outage events is divided by the
23		estimated cost to perform the work to provide a benefit-cost for each impact
24		dimension. To aggregate the benefit-cost ratios across all the impact dimensions,
25		safety, reliability, and cost avoidance, benefit-cost ratios are indexed to scores of

1 0-100. In similar manner to the GPM, each impact dimension is multiplied by a 2 weighting factor of 10 for safety, 3 for reliability, and 3 for cost avoidance. The 3 Company recognizes that other priorities could impact the execution order of ISO 4 down conversion. Other priorities that are considered include, but is not limited to, 5 load growth and jumpering creation. 6 7 City of Detroit Infrastructure (CODI) Upgrades 8 What areas of Detroit will be addressed by the CODI program? **Q38**. 9 A38. Figure 1 below shows the areas of Detroit that will be addressed by the CODI 10 program which includes a core area from Downtown to the Midtown and New 11 Center areas and an extended area including Eastern Market, Corktown, and the 12 West and East River Fronts. There are 31,800 customers served in this area 13 including 27,486 residential, 4,299 commercial, and 15 industrial customers. In 14 addition to residential, commercial, and industrial customers including healthcare 15 facilities and universities, this area of Detroit is also vital to tourism and recreation

- 16 in the region, with an abundance of shopping, sports venues, and parks.
- 17

#### Figure 1 CODI Scope Area



18



2 Q39. Why is the CODI program needed?

3 A39. The earliest electrical grid in southeast Michigan was developed in the downtown 4 area in the city of Detroit. Significant portions of the electrical infrastructure in 5 Detroit were placed in service in the early part of the 20th century, and much of 6 that earlier infrastructure remains. Additionally, certain sections of Detroit have 7 seen significant economic growth. Redevelopment in the City of Detroit is stressing 8 this aging infrastructure, and new customer load cannot be served with existing 9 capacity. The downtown CODI area has been experiencing load growth since 2012, 10 with potential for up to 20% of additional load growth by the end of 2023. Due to 11 significant cable network configuration in the CODI area, substation and circuit 12 upgrades must be sequenced and conducted in a robust, multi-year program as 13 opposed to individual episodic projects to address the interdependency of the 14 system. These projects require system shutdowns that will need to be managed 15 carefully due to the critical customer loads that will be impacted, including 16 hospitals. The Company has developed the CODI program for that purpose. It is 17 important to note that the load growth that has been realized over the last 10 years is not the only driver of this program. The electrical infrastructure (substations, 18 19 underground cable, manholes, network equipment, and other assets) in this area has 20 served the customers well over many decades. However, this infrastructure is 21 experiencing higher failure rates, increasing the risk of long-duration outages 22 impacting customers, and which can lead to high reactive maintenance costs. The 23 continued implementation of the CODI program is necessary to address this aging 24 infrastructure to serve the customers safely and reliably in this area.

25

#### SSD-24
#### 1 **Q40.** What is the scope of the CODI Upgrades program?

2 A40. The downtown CODI program is different from other conversions projects due to 3 the presence of large amounts of system cable and secondary network cable. This 4 adds to the complexity of operating, maintaining, and upgrading this part of the 5 system. Due to significant cable network configuration in the CODI area, substation 6 and circuit upgrades must be sequenced and conducted in a robust, multi-year 7 program as opposed to individual projects to address the interdependency of the 8 system. Between 2021 and 2024, investments have and will be made into ten CODI 9 projects including the targeted network secondary cable replacement program. 10 Table 5 highlights these projects with additional detail provided in Exhibit A-23 11 Schedule M5.

Project	Key Scope of Work	Estimated Timeline
CODI: Charlotte Network Upgrade	<ul> <li>* Rebuild 30 miles of network feeder cable</li> <li>* Rebuild 7 miles of system cable</li> <li>* Replace or remove 83 netbank transformers</li> <li>* Convert 8 primary customers</li> <li>* Convert the circuits to 13.2kV</li> <li>* Decommission Charlotte substation</li> </ul>	2018-2025
CODI: Targeted Network Secondary Cable Replacement	Replace targeted sections of the secondary network cable system that have a higher probability of failure	2019-2025
CODI: Corktown Substation	Build a new general purpose substation	2019-2022
CODI: Islandview Substation	*Construct a new 13.2kV substation * Convert 32 existing 4.8kV circuits from Walker and Pulford *Decommission Waler substation * Decommission aging 24kV cables and infrastructure	2020-2028
CODI: CATO Substation Expansion	Expand 13.2kV Cato substation by installing a 3rd transformer and a 12-position switchgear	2022-2027
CODI: Howard Conversion	<ul> <li>* Rebuild 6 miles of network feeder cable</li> <li>* Rebuild 12 miles of system cable</li> <li>* Replace or remove 89 netbank transformers</li> <li>* Convert 26 primary customers</li> <li>* Convert 3 miles of overhead</li> <li>* Convert and consolidate the circuits to 13.2kV fed by Corktwon, St. Antoine, Cato, and Temple substations</li> <li>* Decommission Howard substation</li> </ul>	2023-2030

# Table 4 City of Detroit Infrastructure Projects

3

Line <u>No.</u> Line <u>No.</u>

## **S. S. DEOL** U-21297

Project	Key Scope of Work	Estimated Timeline
CODI: Midtown Substation Expansion	Expand 13.2kV Midtown substation by installing a 3rd transformer and a 12-position switchgear	2019-2023
CODI: Alfred Substation Expansion	Expand 13.2kV Alfred substation by installing a 3rd transformer and a 12-position switchgear	2021-2024
CODI: Garfield Network Upgrade	<ul> <li>* Rebuild 36 miles of network feeder cable</li> <li>* Replace or remove 78 netbank transformers</li> <li>* Convert 24 miles of overhead</li> <li>* Convert and consolidate the circuits to 13.2kV fed</li> <li>by Stone Pool substation</li> <li>* Remove 4.8kV and 24kV cable and decommission</li> <li>Garfield substation</li> </ul>	2020-2028
CODI: Kent/Gibson Conversion	Kent Substation <ul> <li>Rebuild 6 miles of system cable</li> <li>Convert 1 primary customer</li> <li>Convert 7 miles of overhead</li> <li>Convert and consolidate the circuits to 13.2kV fed</li> <li>by Corktown substation</li> <li>Decommission and remove 2 miles of 4.8kV cable</li> <li>Remove 24kV cable and equipment</li> <li>Remove 6 breakers and decommission Kent</li> <li>substation</li> <li>Gibson Substation</li> <li>Rebuild 10 miles of system cable</li> <li>Convert 22 miles of overhead</li> <li>Convert and consolidate the circuits to 13.2kV fed</li> <li>by Corktown substation</li> <li>Rebuild 10 miles of system cable</li> <li>Convert 22 miles of overhead</li> <li>Convert and consolidate the circuits to 13.2kV fed</li> <li>by Corktown substation</li> <li>Decommission and remove 4 miles of 4.8kV cable</li> <li>Remove 24kV cable and equipment</li> <li>Remove 24kV cable and equipment</li> </ul>	2021-2027

# Q41. How are conversion and CODI projects benefiting customers in the City of Detroit?

A41. While approximately 14% of the Company's customers are in the city of Detroit,
the Company is investing over 30% of its 2022-2024 strategic capital in the city
(Table 3). These projects address aging infrastructure, improve safety and
reliability of the distribution system. The CODI and conversion projects in the
instant case will convert the system that serves more than 50,000 residential Detroit
customers to 13.2kV from 4.8kV.

## Table 5Key Investments in the City of Detroit

11

10

9

Project/Program	Exhibit /Schedule	Page No. /Line No.	2022 - 2024 Capital Investment in City of Detroit (\$thousands)	2022 - 2024 Percent of Startegic Capital in City of Detroit vs Total Strategic Capital
Substation Risk: McGraw	A-12 B5.4	Pg. 8/Ln. 9	40,463	1.7%
Substation Risk: Voyager	A-12 B5.4	Pg. 8/Ln. 10	200	0.0%
4.8 kV Hardening	A-12 B5.4	Pg. 8/Ln. 12	231,314	9.8%
Cable Replacement: Detroit URD 1-1	A-12 B5.4	Pg. 8/Ln. 19	1,061	0.0%
Station Upgrade: Navarre	A-12 B5.4	Pg. 8/Ln. 28	330	0.0%
Subtransmission Redesign & Rebuild: Trunk 2255	A-12 B5.4	Pg. 9/Ln. 11	2,373	0.1%
Subtransmission Redesign & Rebuild: Trunk 2419	A-12 B5.4	Pg. 9/Ln. 32	954	0.0%
Subtransmission Redesign & Rebuild: Trunk 2455	A-33 X3	Pg. 1/Ln. 21	1,995	0.1%
Subtransmission Redesign & Rebuild - Waterman	A-12 B5.4	Pg. 10/Ln. 55	2,310	0.1%
Subtransmission Redesign & Rebuild: Cortland Station Expansio	A-12 B5.4	Pg. 10/Ln. 60	3,630	0.2%
CODI: Charlotte Network Upgrade	A-12 B5.4	Pg. 10/Ln. 60	26,617	1.1%
CODI: Targeted Network Secondary Cable Replacement	A-12 B5.4	Pg. 10/Ln. 61	9,389	0.4%
CODI: Corktown Substation	A-12 B5.4	Pg. 10/Ln. 62	1,360	0.1%
CODI: Islandview Substation	A-12 B5.4	Pg. 10/Ln. 63	95,082	4.0%
CODI: CATO Substation Expansion	A-12 B5.4	Pg. 10/Ln. 64	24,414	1.0%
CODI: Howard Conversion	A-12 B5.4	Pg. 10/Ln. 65	15,702	0.7%
CODI: Midtown Substation Expansion	A-12 B5.4	Pg. 10/Ln. 66	4,037	0.2%
CODI: Alfred Substation Expansion	A-12 B5.4	Pg. 10/Ln. 67	15,973	0.7%
CODI: Garfield Network Upgrade	A-12 B5.4	Pg. 10/Ln. 68	84,413	3.6%
CODI: Kent/Gibson Conversion	A-12 B5.4	Pg. 10/Ln. 69	61,611	2.6%
4.8 kV CC: Cortland / Oakman / Linwood Consolidation	A-12 B5.4	Pg. 10/Ln. 72	387	0.0%
4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)	A-12 B5.4	Pg. 10/Ln. 74	57,607	2.4%
4.8 kV CC: McKinstry Sub Decommission	A-12 B5.4	Pg. 10/Ln. 79	4,696	0.2%
4.8 kV CC: Power line Conversion of MADSN 175L-W	A-12 B5.4	Pg. 10/Ln. 91	361	0.0%
4.8kV CC: SCOTN	A-12 B5.4	Pg. 11/Ln. 94	3,846	0.2%
4.8 kV CC: Zenon Circuit Conversion Phase 2	A-33 X3	Pg. 1/Ln. 7	800	0.0%
Pilot: Strategic and Service Undergrounding	A-12 B5.4	Pg. 11/Ln. 132	4,454	0.2%
Pilot: Primary Deconductoring	A-12 B5.4	Pg. 11/Ln. 133	1,848	0.1%
4.8 kV Relay Improvement (Delta Ground Detection Program)	A-12 B5.4	Pg. 12/Ln. 39	47,127	2.0%
Total			744,354	31.5%
SSD-28				

Line <u>No.</u>

Line		<b>S. S. DEOL</b> U-21297
<u>No.</u>		
1		
2	<u>8</u>	8.3 kV Pontiac Conversion
3	Q42.	Why does the Company operate at a different grid voltage, 8.3kV, in the
4		Pontiac area?
5	A42.	The 8.3kV system that serves the city of Pontiac was acquired from CMS Energy
6		in the 1980s. More detail on the 8.3kV system can be found in Exhibit A-23
7		Schedule M7 DGP beginning on page 341.
8		
9	Q43.	What are the drivers of the 8.3 kV Pontiac Conversion?
10	A43.	The Pontiac area is the only 8.3kV in the Company's distribution system. Unlike
11		the 4.8kV and 13.2kV systems, contingency options through jumpering are limited
12		for the 8.3kV system, because the 8.3kV system is an island surrounded by the
13		13.2kV system, it is challenging to transfer load from 13.2kV to 8.3kV and from
14		8.3kV to 13.2kV to transfer load from 8.3kV circuits to neighboring facilities. This
15		results in a high risk for stranded load in the event of a substation outage event.
16		
17		Adding to the operational challenges, the 8.3kV system is aged, and replacement
18		parts are no longer available. Due to the design configuration and timeframe when
19		these substations were built, they now have non-standard clearances. For Company
20		employees to maintain safe working conditions, to prevent arc flashes, substation
21		shutdowns are required versus isolating a single piece of equipment. This leads to
22		extended customer interruptions during outage events and leaves the system in an
23		abnormal state for extended periods of time if any 8.3kV equipment fails.
24		

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For reasons listed above and to increase capacity, improve reliability, safety, and operability, the Company has developed plans to upgrade and convert the Pontiac system to 13.2kV as part of grid modernization.

4

### 5 Q44. What are the benefits of the 8.3kV Pontiac Conversion?

6 A44. Expanding and upgrading the 13.2kV Wheeler substation will allow for conversion 7 of the 8.3kV Pontiac system. Converting the Pontiac system to 13.2kV will provide 8 jumpering points from nearby 13.2kV substations and shorten outage times by 9 allowing the Company to restore customers prior to repairing all the damaged 10 infrastructure (restore before repair). The expanded 13.2kV Wheeler substation 11 will also provide for capacity needs in the future and better prepare the area for 12 adoption of DERs. Additionally, this project will decommission all four 8.3kV 13 substations and the 13.2kV Bloomfield substation that has been identified to have 14 at-risk switchgear. Removing at-risk, outdated, and obsolete 8.3kV equipment from 15 the system will reduce emergent cost and improve response time for customer 16 restoration.

17

### 18 Q45. What is the scope of the 8.3kV Pontiac Conversion?

A45. The 8.3kV system is served by four substations: Bartlett, Paddock, Rapid Street,
and Stockwell, and their combined eighteen distribution circuits. The plan to
address the 8.3kV system has been developed, starting with upgrading the system
vaults as outlined in previous rate cases and in Section 8.19 of the DGP. The
remaining scope of work for the 8.3kV system includes upgrading the existing
13.2kV Wheeler substation and transferring the feed to all remaining OH and
underground infrastructure from Bartlett, Paddock, Rapid Street, and Stockwell to

the upgraded substation. This will require replacement of customer-owned switchgear, fuses, transformers, and cables rated at less than 15kV class.

3

2

1

#### 4 <u>Subtransmission Redesign & Rebuild</u>

### 5 Q46. Can you describe the Company's Subtransmission system?

6 A46. The Company's subtransmission system is an interconnected web that transmits 7 higher voltage across the service territory to stations that step down the voltage to 8 distribution levels to serve customers. The subtransmission system is operated at 9 the voltages of 24kV, 40kV, or 120kV. The design of the system is intended to provide redundancy to the feed points of the distribution substations which directly 10 11 serve customers. This redundancy provides continued service to the customers 12 during a single contingency situation. This situation is caused by an outage of 13 equipment in the OH, UG, or station system that is necessary to allow power flow 14 to customers. The Company's subtransmission system differs from that of most 15 other utilities because it includes both radial and network designs. The radial 16 configuration, called a trunk line, has one source station and can feed one or 17 multiple substations. The network configuration, called a tie line, has multiple 18 source stations and feeds multiple substations. The Company utilizes a coordinated system of automatic pole top switches (APTS) and line section breakers on the 19 20 networked tie lines to isolate faults and maintain service to customers in single 21 contingency failure situations.

22

Q47. What are the challenges and issues associated with the subtransmission
system?

1 A47. Similar to the distribution system, the subtransmission system is experiencing 2 aging, beyond 80 years old in some areas, and storm related reliability challenges, 3 as well as increased loading and a loss of contingencies. Areas of the 4 subtransmission OH system are in difficult-to-access, deeply wooded areas and 5 along railroads, increasing the time and difficulty for restoring service or 6 maintaining equipment. These factors are leading to an increased number of failures 7 on both the OH and underground subtransmission systems and delaying 8 restorations. These failures result in large sustained outage and the loss of 9 redundancy, depending on the system configuration. 10 The Company performed an analysis on the subtransmission system that revealed

10 The Company performed an analysis on the subtransmission system that revealed
 11 approximately one-third of the circuits on the subtransmission system violated the
 12 Company's planning criteria and need to be addressed, described in Table 6.

13

1

Subtransmission Dimensions	Definition
Load Loss for Single Contingency	Total load that will be shed when a subtransmission line can no longer support the substation and does not have a back-up or the back-up cannot support the load
Load over allowable Emergency Rating for Single Contingency	Total load when a subtransmission line exceeds its emergency rating of its alternative route during an event (i.e., outage)
Load over Day to Day Rating, Normal Conditions	Total load that exceeds the rating of a subtransmission line during normal conditions
Strong Load Growth Prospect	Consideration given to subtransmission lines that are predicted to experience load growth
Voltage Violation	Consideration given to subtransmission lines that experience low voltage conditions when they are not in their normal configuration (i.e., due to an outage)
Reliability Impact	Consideration given for the reliability of the subtransmission lines based on total sustained outages, miles of circuit exposure, construction standards & equipment, total customers and total load served and ability to serve the load from an alternate source

2 Additionally, the analysis showed that the Company's aging subtransmission 3 system is not currently adequate to serve the Company's customers' long-term 4 needs given its limited capacity and reliability performance. System loading and 5 the impact of outages on customer operations have increased over time and reduced 6 the redundancy. Existing overloads and the aging equipment place loading 7 constraints on the system. These constraints limit the Company's ability to get 8 shutdowns required for system upgrade projects and routine maintenance can only 9 be completed during periods of low load or through the deployment of portable 10 equipment. These periods of low load are typically only during a few weeks in the

2 3

4

5

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Q48. What analysis was performed to determine that circuits on the subtransmission system violate planning criteria?

customers or provide capacity for existing customers with increased load.

spring and the fall. The loading constraints also make it challenging to add new

6 A48. Subtransmission Planning Engineers analyze the condition of the system on a 7 yearly basis to determine existing and projected limitations to serving customers in 8 a single contingency situation. This analysis is conducted by utilizing industry-9 standard modeling software (PSSE & TARA) with individual substation loads 10 submitted by Company SMEs and the models used by the Midcontinent 11 Independent System Operator (MISO). The models provided by MISO include 12 multiple electric system scenarios, including current and future peak loading 13 conditions. Using these models, a study is run on each individual subtransmission 14 line with all possible contingency situations assessed to identify all violations of 15 subtransmission planning criteria. The planning criteria focuses on both thermal 16 overloads and voltage violations under normal system conditions and during a 17 single contingency configuration. A thermal overload indicates that equipment on 18 the circuit or station exceeds its rating, and a voltage violation indicates that the 19 voltage on at least part of the circuit is no longer within an acceptable range.

20

# Q49. Why does the Company need to redesign and rebuild its subtransmission system?

A49. This rebuilt hardened resilient subtransmission system will dramatically improve
 safety, reliability, operability, and increase capacity. The resiliency of the OH
 subtransmission system will be achieved by rebuilding to the Company's grade B

standard which will harden against weather impacts such as high winds and lighting. Company's grade B standard is described in more detail below. The rebuilt OH subtransmission system will have larger conductor to provide additional capacity and reduce voltage drop over long distances. The underground subtransmission reliability will improve due to the removal of at-risk or overloaded cables. Additionally, rebuilding the subtransmission system will also remove aging equipment reducing the probability of equipment failures.

8 An outage event on the distribution system could impact up to 1,000+ customers, 9 based on the size of the circuit. By comparison, an outage on the subtransmission 10 system could impact multiple substations resulting in up to 10,000+ customers 11 impacted. Furthermore, subtransmission outages typically require the deployment 12 of costly mobile generation or portable substations to restore customers quickly 13 because permanent solution take extended periods of time to implement. The rebuilt 14 subtransmission system by design will provide redundancy to reduce/eliminate 15 multiple substation outages.

16 This rebuilt and redesigned subtransmission system will support area load growth 17 for existing and new customers. Along with the ability to support DER 18 interconnections, such as large-scale solar arrays. As the generation profile is 19 expected to change with the integration of more DERs and the retirement of fossil 20 generation plants, improvements to the subtransmission system will support the 21 changing power flows on the system.

22

Line

No.

#### 23 Q50. What is the scope of the Subtransmission Redesign & Rebuild program?

A50. The subtransmission redesign and rebuild program is focused on installing new
 station equipment, as well as rebuilding both the OH and underground portions of

Line	
No	

16	051	How did the Company develop the Subtransmission Redesign & Rebuild
15		
14		new sections and rebuilding cable poles to new specifications.
13		on it. The underground work consists of replacing at-risk or overloaded cable with
12		of existing conductors to withstand contact with a tree limb if one happens to fall
11		over long distances on the system and providing approximately twice the strength
10		more capacity on each circuit, while also reducing the magnitude of voltage drop
9		resilient system. The larger wire standard conductor will provide significantly
8		conductors able to withstand winds up to 90 mph resulting in a much more storm
7		conductors – which can be damaged by lightning strikes – with larger wire, stronger
6		porcelain insulators with polymer clamp top insulators, and smaller wire aging
5		standards which include the replacement of old wooden poles with new steel poles,
4		support. The OH work will be completed to our updated, more resilient grade B
3		significant improvements to the system with additional redundancy and voltage
2		transformers, capacitor banks and associated equipment, and will provide
1		the subtransmission system. The station work involves the installation of large

# 16 Q51. How did the Company develop the Subtransmission Redesign & Rebuild 17 Plan?

- A51. In order to determine the subtransmission projects that would have the greatest
  impact on reliability and resiliency of the system, the Company reviewed:
- 20 1) current system planning criteria violations, related to loading and voltage21 challenges;
- 22 2) future distribution system plans and loading projections;
- 23 3) and customer outages caused by subtransmission failures.
- The Company then ranked the planning criteria violations based on severity, and projects were identified that could address the limiting elements on the system. The

Line No.

> 1 scope of the projects and future subtransmission system configuration is also 2 influenced by distribution system plans to construct new and retire old substations. 3 These plans provide the necessary input to ensure the scope of the subtransmission 4 projects will meet the requirements of our customers for decades to come. In 5 addition to planning criteria violations and future distribution system plans, the 6 Subtransmission Planning Engineering group also closely monitors the reliability 7 of the system and identifies circuits with multiple reliability issues. These circuits 8 are identified, and the outages are analyzed to determine the most effective project 9 to improve reliability performance. The Planning Engineers consider both existing 10 routes of the lines that may need rebuilding in place, and sections where wire down 11 events have occurred, which might merit relocation. Based on their analysis, the 12 Planning Engineer identifies which sections to focus on for redesign and rebuild of 13 the lines. The projects that address these sections include rebuilding to the current 14 more resilient construction standards and relocating the lines to road accessibility 15 wherever possible.

16

# Q52. How does the Company determine priorities when selecting circuits for Subtransmission Redesign & Rebuild?

A52. The order in which the circuits and stations will be addressed is determined by
working with the distribution Planning Engineers to collaborate on
conversion/consolidation projects and the priority criteria, which is evaluated over
the whole system on an annual basis.

The Company considers multiple criteria when evaluating the priority of the subtransmission redesign and rebuild projects. Consistent with the rest of the strategic investment portfolio, the load relief prioritization scores for Line No.

> 1 subtransmission feed into the GPM model, supported by Company witness 2 Kryscynski, to help formulate the future capital plan. The Load Relief model was 3 updated to incorporate the subtransmission planning criteria for subtransmission 4 redesign & rebuild projects. Subtransmission load relief prioritization scores are 5 determined based on load loss for single contingency, load over allowable 6 emergency rating for single contingency, load over day to day ratings, strong load 7 growth prospect, and whether there is a voltage violation. Please see Table 6 for 8 further description of the criteria. Once subtransmission projects are prioritized 9 they are evaluated through the GPM model to be compared with the rest of the 10 Company's portfolio.

11

#### 12 Q53. Are all the subtransmission redesign projects listed separately in this case?

13 A53. No. There are times when the Company experiences issues on the subtransmission 14 system that are not overly complex, that can be executed without extensive 15 engineering and planning like the other subtransmission projects. These projects 16 are generally small in nature, requiring \$500,000 or less in capital. The scope of work for these projects addresses thermal and voltage violations under either 17 18 normal or single contingency situations. Projects of this nature are identified during 19 the Annual System Review process, which is the same methodology used to 20 identify all the subtransmission projects under the Subtransmission Redesign & 21 Rebuild program. Because the Company experiences these situations every year 22 and they can be solved quickly without extensive engineering and planning, the 23 Company has created a Small Projects and Reserve program. This program will 24 allow the Company to address smaller issues on the subtransmission system in real 25 time without the delay of a more extensive project.

#### SSD-38

Line <u>No.</u>		<b>S. S. DEOL</b> U-21297
1		
2	Q54.	How will customers benefit from the Small Projects and Reserve program?
3	A54.	The Small Projects and Reverse program will provide multiple customer benefits
4		including safety, improved reliability and operability, and increased capacity within
5		a shorter period of time due to the much more limited scope required to address
6		identified system issues. With the ability to address the system conditions and
7		provide more immediate benefits to the customers with a relatively quick solution,
8		the projects are executed shortly after identification instead of following a more
9		formal ranking and scheduling potentially years out.
10		
11	<u>,</u>	Strategic Undergrounding Program
12	Q55.	Has the Company piloted undergrounding existing OH lines?
13	A55.	Yes. The Company initiated a pilot on Appoline DC 1346 in Detroit to move rear-
14		lot OH assets to rear-lot underground infrastructure.
15		
16	Q56.	What were the objectives of the pilot?
17	A56.	As described in the Company's 2021 Distribution Grid Plan (Exhibit A-23
18		Schedule M7), the goals of the Appoline pilot were to determine actual installation
19		costs, understand customer acceptance, and determine opportunities to improve
20		cost and construction efficiency.
21		
22	Q57.	What was the timing of the Appoline undergrounding pilot?
23	A57.	The Company began engineering for the pilot in 2018 and construction started in
24		2019. Of the 61 customers targeted for undergrounding, 21 still remain on OH
25		service. The Company performs undergrounding of services as part of its regular
		SSD-39

Line
No.

1		business practice, typically at the customer's request, and there is nothing additional
2		to learn by undergrounding the remaining customers. This pilot has achieved its
3		primary objective, and therefore, the Company considers it complete. Through this
4		pilot the Company was able to gather the needed lessons learned on undergrounding
5		rear lot OH infrastructure. The Company has completed an initial report, pursuant
6		to the Order in Case No. U-20836, on the Appoline pilot and is included in the
7		instant case as Exhibit A-23 Schedule M10. That report provides additional details
8		on the timing and status of the pilot.
9		
10	Q58.	Is the Company considering other strategic undergrounding projects?
11	A58.	Yes. In the instant case, the Company is proposing an additional undergrounding
12		project for Fairmount DC 1593, which will allow us to continue to develop our
13		understanding of this technology aimed at resilience.
14		
15	Q59.	What is the scope of the Fairmount DC 1593 underground project?
16	A59.	The scope of this undergrounding project differs from Appoline, in that it is to
17		relocate OH rear-lot assets to front-lot URD in a two-block area served by
18		Fairmount DC 1593 in the City of Detroit. It includes installing two cable poles,
19		conduit, and primary conductor to establish the URD loop around the two-blocks.
20		This project will install 14 pad-mounted transformers, 43 secondary pedestals and
21		other necessary equipment to serve approximately 98 customers in the area. All the
22		equipment and the system design will be completed in preparation for conversion
23		to 13.2kV at some point in the future. Once the URD loop is established, and the
24		new services have been completed; the existing OH assets will be removed from
25		the rear-lot.

2 Q60. Why was Fairmount DC 1593 selected?

3 A60. Customers on this circuit have continued to experience a higher-than-average 4 number of downed wires per mile, despite the fact that tree trimming has been 5 completed. Furthermore, in 2021 and 2022 some of the customers on this circuit 6 experienced 5 or more sustained outages and dozens of momentary outages. During 7 the August 9, 2021 catastrophic storm approximately half the customers fed by 8 Farimount DC 1593 were without power for over 50 hours. There were many 9 downed wires in backyards with limited truck access that led to this delayed 10 restoration time. Because of these issues, it was determined that this circuit was a 11 good candidate for undergrounding and would allow the Company to continue its 12 knowledge gathering for undergrounding existing OH infrastructure.

13

#### 14 **Q61.** What is the timing of the Fairmount underground project?

A61. Engineering is being completed and design is expected to start late in the first quarter or early in the second quarter with the intent of starting construction in late fall of 2023. Construction completion is scheduled for the end of 2024. The Company is also employing lessons learned from the Appoline project by beginning to actively engage customers to gain support for the project with the goal to get significant customer approval prior to beginning construction.

21

# Q62. What does the Company expect to accomplish with the Fairmount DC 1593 underground project?

A62. As described earlier in this testimony and Exhibit A-23 Schedule M10, the
Company learned a great deal about the installation costs, customer acceptance and

1	construction efficiency when addressing rear-lot construction by completing the
2	Appoline pilot and benchmarking work. The Fairmount project will leverage these
3	lessons learned by removing OH infrastructure to improve safety and reliability for
4	the customers. The Company has an opportunity to expand its knowledge of
5	designing and implementing front lot underground infrastructure to replace existing
6	rear lot OH infrastructure. When this project is completed, the Company will have
7	additional data to support a more statistically significant benefit cost analysis for
8	undergrounding projects.

9

10

#### Primary Deconductoring

### 11 Q63. What are the benefits of the Primary Deconductoring?

A63. The driving benefit is that by removing OH lines that are not fully utilized, and any associated arc wire, the Company is eliminating wire downs. Removing unnecessary OH lines also eliminates the potential for power outages caused by those lines failing or being damaged. As the Company installs new secondary lines where needed they are installed at the new standard, larger size, meaning they are stronger and are rated for higher voltages. Any transformers installed are also to the new standards, dual voltage, and are rated for 13.2kV.

19

#### 20 **Q64.** What is the scope of work for Primary Deconductoring?

A64. The scope of work for Primary Deconductoring includes the removal of underutilized infrastructure such as small-sized primary wire, arc wire, OH transformers, and other pole top equipment. In addition, where necessary the Company will reconductor secondary wires and upgrade transformers and other

Lina		S. S. DEOL
No.		0-212)7
1		pole top equipment, and where possible install equipment in truck accessible
2		locations.
3		
4	Q65.	Has the Company completed the Primary Deconductoring pilot?
5	A65.	Yes. The Company has completed projects on two circuits.
6		
7	Q66.	What are the lessons learned from the Primary Deconductoring pilot?
8	A66.	In the initial phases of the pilot the Company assumed a flat KVA usage per home,
9		this assumption proved to be incorrect and lead to low voltage issues. The Company
10		has moved to a more dynamic assumption for KVA usage per home. This dynamic
11		approach considers the type of housing in the area of work, i.e. number of duplexes,
12		single family homes, etc. Since using this approach, the Company has not
13		experienced any low voltage issues.
14		
15	Q67.	How will Primary Deconductoring be used in the future?
16	A67.	The Company is currently performing deconductoring in the 4.8kV Hardening
17		program, for further detail see the testimony of witness Elliott Andahazy. In the
18		short term the Company will consider deconductoring where appropriate in the
19		4.8kV Conversion program, as well. As results are reviewed and analyzed, the
20		Company will consider if a standalone Primary Deconductoring program is needed.
21		
22	4 <u>1</u>	System Loading
23	Q68.	Can you describe a system overload?
24	A68.	System overloads occur when there is not enough capacity to meet customer
25		demands and still maintain equipment operating ratings. Capacity needs are
		SSD-43

1	considered for two conditions: normal state and contingency states. The normal
2	state exists when all equipment and components are in services and operating as
3	designed. The contingency states exist when there is either a temporary planned
4	equipment shutdown or the loss/failure of a component of the electric power system
5	(e.g., transformer, cable or breaker). Under contingency conditions, equipment in
6	the rest of the system may see an increase in loading to compensate for the out-of-
7	service equipment, therefore requiring additional capacity above normal state.
8	To meet the two capacity requirements, most components and equipment have two
9	ratings: day-to-day and emergency. These ratings are calculated to maintain the
10	viability of an asset throughout its expected useful life. Operating equipment above
11	its designated ratings can cause immediate failure or accelerate end-of-life and is
12	considered an overload.
13	• The day-to-day rating (for normal state conditions) is the load level that the
14	equipment can be operated at for its expected life span.
15	• The emergency rating (for contingency state conditions) is typically higher
16	than the day-to-day rating and indicates the load level that the equipment
17	can operate for short periods of time only. Operating at the emergency rating
18	adds stress to the equipment and shortens its lifespan. If a piece of
19	equipment exceeds its emergency rating, the Company's ESOC takes
20	immediate steps to transfer load or shed load if necessary.
21	• Substations also have a firm rating, which is the maximum load the
22	substation can carry under a single contingency condition and is based on
23	the lowest emergency rating of all the substation equipment that is required
24	to serve the load.
25	

### SSD-44

Line <u>No.</u>

### 1 **Q69.** What are the challenges and issues with system overloads?

A69. System overloads make it challenging for the Company to serve new customers and
provide additional capacity for existing customer. System overloads stress
equipment reducing useful life and impacts system operability by limiting
jumpering. Without jumpering capabilities to adjacent circuits, outages can be
sustained for longer periods of time because the equipment must be replaced to
restore customers. Furthermore, stressed equipment can also increase the
probability of emergent failures leading to customer outages.

9 The Company conducts annual Area Load Analysis (ALA) to determine if there are 10 any overloads on the system. Based on the 2021 ALA study, over 30% of 11 distribution substations have loading constraints. This includes substations 12 operating over its firm ratings and substation equipment and/or circuit equipment 13 working near or over its day-to-day rating during peak hours. In areas that have 14 seen and continue to see steady load growth, capital investments are required to 15 prevent overloads.

16

### 17 **Q70.** What are the benefits of System Loading projects?

A70. System Loading alleviate the stress on the system caused by overloads and reduces potential failures. Capital investment to address these system overloads will improve reliability and provide capacity for new customer and increased demand form existing customers. Additionally, the system load projects help maintain/improve system operability by restoring jumpering capabilities and removes aged equipment from the system.

24

25 Q71. What is the scope of work for System Loading projects?

1	A71.	System Loading projects include scope to add capacity to the distribution system,
2		and typically include:
3		• construction of new substations
4		• expansion of current substations by installing additional transformers
5		• replacing existing transformers
6		• installing new switchgear lineups
7		• creating new distribution circuits
8		• reconductoring circuits
9		• converting circuits to higher voltage and transferring load once additional
10		capacity has been created
11		Many areas identified in the priority ranking for system load relief are
12		addressed as part of CODI, 4.8kV Conversion, or 8.3kV Pontiac Conversion
13		programs. Load relief needs that are not included in those programs are part of
14		the System Loading projects category.
15		
16	Q72.	How are system loading projects prioritized?
17	A72.	Distribution engineers assess the load on the system and its impact on individual
18		pieces of equipment under two conditions: normal state and contingency state. This
19		analysis is done to determine if adequate distribution system capacity exists to serve
20		both current and projected future demands.
21		System loading information from this analysis is updated and evaluated annually.
22		Projects are evaluated for load relief on how they address four factors: substation
23		equipment overload, substation over firm, circuit equipment overload, or strong
24		load growth. Based on these variables a priority ranking of the load relief projects
25		is developed. More information about Load Relief criteria and prioritization can be

Line <u>No.</u>		<b>S. S. DEOL</b> U-21297
1		found in Section 11.1 of the DGP (Exhibit A-23 Schedule M7 sponsored by
2		Witness Robinson).
3		
4	Q73.	Does this complete your direct testimony?
5	A73.	Yes, it does.

# STATE OF MICHIGAN

# BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)
DTE ELECTRIC COMPANY	)
for authority to increase its rates, amend	)
its rate schedules and rules governing the	)
distribution and supply of electric energy, and	)
for miscellaneous accounting authority.	)

Case No. U-21297

## QUALIFICATIONS

## AND

## DIRECT TESTIMONY

### OF

## MORGAN ELLIOTT ANDAHAZY

# DTE ELECTRIC COMPANY QUALIFICATIONS AND DIRECT TESTIMONY OF MORGAN ELLIOTT ANDAHAZY Line

No.

1	Q1.	What is your name, business address and by whom are you employed?
2	A1.	My name is Morgan Elliott Andahazy (she/her/hers). My business address is One
3		Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company
4		(DTE Electric or Company).
5		
6	Q2.	On whose behalf are you testifying?
7	A2.	I am testifying on behalf of DTE Electric.
8		
9	Q3.	What is your educational background?
10	A3.	I hold a Bachelor of Science in Engineering (Industrial and Operations
11		Engineering) and a Master of Business Administration, both from the University of
12		Michigan, Ann Arbor.
13		
14	Q4.	Please summarize your professional experience.
15	A4.	In 2007, I joined DTE Electric as a Contract employee supporting the Distribution
16		Operations Continuous Improvement (DOCI) team. In March 2008, I joined DTE
17		Electric as a full-time employee and a Project Lead within the DOCI team. As a
18		Project Lead, I was responsible for measuring and improving productivity within
19		the Electric Field Operations (EFO) organization. During this time, I obtained my
20		Lean Six Sigma Black Belt certification based on work I did with EFO Productivity
21		projects. In 2009, I transitioned to the Continuous Improvement (CI) Manager for
22		Distribution Operations (DO) where I was responsible for the team of Project Leads
23		supporting improvement projects throughout DO. In March 2010, I moved to a new

1 developmental assignment as a Field Supervisor for the Underground (UG) Cable 2 Pulling team at the Trombly Service Center. At Trombly, I was responsible for 3 overseeing the daily construction work performed by the UG Cable Pullers and 4 supervising a Union represented workforce. In January 2011, I was promoted to 5 the CI Manager for Corporate Services. I was responsible for coordination and 6 implementation of CI training to the organization, and I led the team of CI experts 7 responsible for improvement projects. In October 2011, I transitioned to Manager, 8 Trombly Service Center, where I was responsible for all UG operations (cable 9 pulling and cable splicing) for the Southeast (SE) Region of DO. In April 2013, 10 my role expanded to Manager, SE Region, which consisted of three service centers 11 (Trombly, Redford, and Caniff) and included all Overhead (OH) and UG 12 operations in the SE Region. In March 2016, I was promoted to Director, Service 13 Operations responsible for all OH and UG operations in Southwest (SW), 14 Northwest (NW), and Northeast (NE) regions in DO. In this role, I also assisted in 15 Local 17 contract negotiations. In October 2017, I assumed the position of 16 Director, Advanced Distribution Management System (ADMS). I lead the team 17 responsible for the successful implementation of the new ADMS. This team was 18 responsible for the strategic direction, vendor selection, and implementation of all 19 ADMS components including the Generation Management System (GMS), 20 Energy Management System (EMS), Outage Management System (OMS), 21 Distribution Management System (DMS), and the Network Management System 22 (NMS). In April 2022, I transitioned to my current role as the Director, Project 23 Management Organization (PMO) within Electric Distribution Operations (DO).

24

Line

No.

<u>No.</u>		
1	Q5.	Do you hold any certifications or are you a member of any professional
2		organizations?
3	A5.	In 2009, I received my Lean Six Sigma Black Belt certification.
4		
5	Q6.	What are your current duties and responsibilities?
6	A6.	As Director, PMO, I lead the team that is responsible for managing the execution
7		of the projects and programs that make up the majority of the Strategic Capital
8		Budget for DO. My team consists of the project managers, cost engineers,
9		schedulers, project estimators, and the leadership/support teams required to manage
10		and track the progress of our investments.
11		
12	Q7.	Have you previously sponsored testimony before the Michigan Public Service
13		Commission (MPSC or Commission)?
14	A7.	Yes. I have sponsored testimony in the following case:
15		U-20836 2022 DTE Electric Rate Case

Line

### 1 **Purpose of Testimony**

### 2 **Q8.** What is the purpose of your testimony?

3 A8. As referenced in Witness Robinson's description of the distribution witnesses, the 4 purpose of my testimony is to support, as reasonable and prudent, the historical 5 capital expenditures for 2021 and projected capital expenditures for 2022 to 6 November 30, 2024, in the distribution strategic category of Infrastructure 7 Resilience and Hardening, and the investments in the System Operations Center 8 (SOC) Modernization projects which include the construction of the new Electric 9 System Operations Center (ESOC) and the Alternate Systems Operations Center 10 (ASOC), for the same period. In addition, my testimony will include support for 11 specific programs included in the Infrastructure Recovery Mechanism (IRM) 12 proposed by Company Witness Foley.

13

14

#### Q9. Are you sponsoring any exhibits in this proceeding?

15 A9. Yes. I am sponsoring the following exhibits:

16	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
17	A-12	B5.4	Projected Capital Expenditures –
18			Distribution Plant
19			(Pages 1, 2, 8, 12-15, 19)
20	A-12	B5.4.8	4.8 kV Hardening & Pole and Pole Top Maintenance
21			and Modernization (PTMM) – Details
22	A-23	M4	Distribution Plant Capital Project Detail –
23			Infrastructure Resilience and Hardening
24	A-23	M6	Distribution Plant Capital Project Detail –
25			Technology and Automation

Line No.

				Μ ΕΙΙΙΟΤΤ ΑΝΝΑΗΑΖΥ
Line <u>No.</u>				U-21297
1		A-23	M8	Wood Pole Maintenance Specification
2		A-23	M9	Pole Top Maintenance Specification
3		A-33	X2	Distribution – Base Rate Investments +
4				Infrastructure Recovery Mechanism
5		A-33	X3	Distribution – Infrastructure Recovery Mechanism
6				
7	Q10.	Were the	se exhibits pr	epared by you or under your direction?
8	A10.	Yes, they	were.	
9				
10	Q11.	How is ye	our testimony	organized?
11	A11.	My testin	nony consists o	of the following parts:
12		Part I Infr	astructure Rec	overy Mechanism (IRM) Support
13		Part II Inf	rastructure Re	silience and Hardening
14		Part III S	ystem Operatio	on Center (SOC) Modernization
15				
16	<u>Part l</u>	Infrastru	cture Recover	y Mechanism (IRM) Support
17	Q12.	Is the Co	mpany propo	sing that any of the capital programs discussed in your
18		testimon	y and exhib	its be associated with the Company's proposed
19		Distribut	ion Infrastru	cture Recovery Mechanism (IRM)?
20	A12.	Yes. As	part of the IR	RM proposal put forth by Company Witness Foley, the
21		Company	is proposing	that the Breaker Replacement program and the URD
22		Replacem	ent program in	nvestments be authorized for IRM treatment.
23				

24

#### Line No.

# Q13. Why does the Company believe that it is appropriate for these programs to be authorized for IRM treatment?

A13. The Breaker Replacement and URD Replacement programs are appropriate for the
Distribution IRM because they are key routine reliability programs that the
Company needs to perform to maintain a safe, and reliable system.

6

7 The Company operates approximately 6,000 circuit breakers, and out of the total 8 population, approximately 60% are considered candidates for replacement due to 9 factors such as equipment condition, age, lack of available parts, and environmental 10 concerns. Additionally, a circuit breaker failure can cause outages on multiple 11 circuits and could reduce system redundancy for extended periods of time. A well-12 funded breaker replacement program is necessary for the successful operation of 13 the distribution system. Additional information on the need for the Breaker 14 Replacement program is provided later in my testimony, in Exhibit A-23 Schedule 15 M4 sponsored by me, and Exhibit A-23 Schedule M7 sponsored by Company 16 Witness Robinson.

17

18 The Company has approximately 11,000 miles of underground residential 19 distribution (URD) cable, of which approximately 19% is cross-linked 20 polyethylene (XPLE) cable installed prior to 1985 and is prone to high failure rates 21 due to a manufacturing flaw known as "water treeing". Water treeing is a 22 breakdown of the insulation that allows water to enter the cable and causes faults 23 (failures). Replacement of this cable will take years and will require an 24 appropriately funded URD program. Additional information on the need for the No. 1 URD Replacement program is provided later in my testimony, and in Exhibit A-23 2 Schedule M7 sponsored by Company Witness Robinson. 3 4 Q14. What level of investment is the Company proposing that the Commission 5 authorize under the Distribution IRM for these programs? 6 A14. As discussed by Company Witness Foley, the Company is proposing a roughly 3-7 year IRM beginning concurrent with the projected test year in the instant case (i.e., 8 December 1, 2023). The Company is proposing that IRM Plan in Year 1 be 13 9 months such that subsequent IRM plan years are aligned to calendar years. As 10 captured in Company Witness Foley's Exhibit A-33, Schedule X1, I am proposing 11 the following investment level shown in Table 1 for the programs I am supporting 12 in the instant case.

13

Line

14

Table 1	Distribution IRM Investments (\$ millions)

Program	Projected Test Year (12 mos. ending 11/30/24)	Plan Year 1 (13 mos. ending 12/31/24)	Plan Year 2 (12 mos. ending 12/31/25)	Plan Year 3 (12 mos. ending 12/31/26)
Breaker Replacement	\$14.0	\$15.2	\$14.0	\$14.0
URD Replacement	\$15.0	\$16.3	\$15.0	\$15.0

15

16 As described by Company Witness Foley, if the Company were to invest less than 17 these levels, the associated over-recovery of costs would be refunded to customers.

1		
2		The level of Distribution IRM Investments for the projected test year (12 months
3		ending 11/30/24) is supported on Exhibit A-33, Schedules X2 and X3, sponsored
4		by Company Witnesses Hill, Deol, and me. Schedule X2 distinguishes expenditures
5		included in the base rate request from the amounts included in the IRM request,
6		while Schedule X3 details the IRM investments in detail by project.
7		
8		For the Breaker Replacement and URD Replacement programs, I am sponsoring
9		an investment level of \$14.0 million and \$15.0 million, respectively, for 12 months
10		ending 11/30/2024 on Exhibit A-33, Schedule X3, Lines 31 and 32. These amounts
11		are also shown on Exhibit A-33, Schedule X2, lines 10 and 11, column (c), as part
12		of the IRM expenditures separate from other Infrastructure Resilience and
13		Hardening expenditures included in the base rate request on line 9, column (b).
14		
15	Q15.	What does the Company intend to accomplish for these programs during the
16		IRM timeframe?
17	A15.	More detail on these programs and why they are beneficial to customers is provided
18		later in my testimony and in Exhibit A-23 Schedule M4.
19		
20	Q16.	How will the Company select specific projects to execute during the IRM
21		timeframe?
22	A16.	The Company's subject matter experts (SMEs) determine the prioritization of
23		breaker replacement and URD replacement. Exhibit A-23 Schedule M7 section 8.3
24		discusses the breaker replacement criteria, and Exhibit A-23 Schedule M7 section
25		8.17 discusses the URD replacement criteria. Company Witness Foley also

Line <u>No.</u>

<u>No.</u>	
1	discusses the Company's proposed process to engage with the Michigan Public
2	Service Commission (MPSC) Staff on investment plan details before each annual
3	IRM period.
4	
5 Q17.	Is the Company proposing to begin reporting any program execution metrics
6	associated with these programs?
7 A17.	Yes. As part of the IRM Reconciliation Process described by Company Witness
8	Foley, the Company is proposing to begin reporting the metrics shown in Table 2.
9	Table 2IRM Program Execution Metrics

Programs	Program Execution Metrics*
Breaker Replacement	<ul> <li>Number and type of breaker replaced</li> <li>Average cost per breaker replaced (by type)</li> </ul>
URD Replacement	<ul> <li>Miles of URD replaced</li> <li>Average cost per mile of URD replaced</li> </ul>

\*measured vs. target

10

Line

11 (	110	
11 (	218.	what is the benefit of IRM treatment for the proposed capital programs?

As further discussed by Company Witness Foley, there are four key benefits of a 12 A18. 13 **Distribution IRM:** 

Certainty of investment. The approval of an IRM effectively establishes a 14 -15 dedicated funding source for capital programs critical to customer safety, customer reliability, and the integration of increasing levels of Electric Vehicles (EVs) and 16 17 other Distributed Energy Resources (DERs). The Company would not be able to

Line <u>No.</u>		U-21297
1		shift investment authorized for IRM treatment to programs outside the IRM, or
2		between programs within it. Importantly, any underinvestment in the programs
3		associated with the IRM would be returned to customers.
4		
5		- Greater transparency. As part of the Distribution IRM, a new planning and
6		reconciliation process would be established that would provide Staff with
7		greater transparency into the Company's investment plans and its execution
8		of those plans.
9		
10		- Opportunities for feedback. As part of the IRM Planning Process, Staff
11		would have the opportunity to review and provide feedback on the
12		Company's planned IRM investments for the upcoming year. Likewise, the
13		Company would then have the opportunity to address that feedback and
14		respond to any questions or concerns raised by Staff before execution of its
15		plans.
16		
17		- Increased accountability. As part of the IRM Reconciliation process, the
18		Company would begin reporting new program execution metrics to help
19		assess its execution of its investment plans.
20		
21	<u>Part I</u>	I Infrastructure Resilience and Hardening
22	Q19.	What is Distribution Infrastructure Resilience and Hardening?
23	A19.	Infrastructure Resilience and Hardening includes projects and programs focused on
24		near-term grid infrastructure investments to harden the system against an increasing
25		frequency and severity of high winds and storms, addressing frequent outage

1		circuits, and replacing aging infrastructure. These investments support employee
2		and public safety, customer reliability, and reduce risk to the grid. Capital
3		investment details of these projects and programs in this category are included in
4		Exhibit A-12, Schedule B5.4, page 8 and Exhibit A-23, Schedule M4. Also
5		included on Exhibit A-12, Schedule B5.4 for this category is AFUDC on page 13
6		and plant activity on pages 14 and 15, described in more detail by Company
7		Witness Miller.
8		
9	Q20.	Are there specific Infrastructure Resilience and Hardening programs you
10		would like to discuss in more detail?
11	A20.	Yes. I would like to highlight the following programs because I believe discussion
12		beyond what is contained in the exhibits will be helpful in establishing a deeper
13		understanding of the scope, the rationale for making the investments, and the
14		benefits customers will receive:
15		• 4.8kV Hardening Program
16		• Pole and Pole Top Maintenance and Modernization (PTMM)
17		Cable Replacement Program
18		Underground Residential Distribution (URD) Replacement Program
19		Breaker Replacement Program
20		• Frequent Outage Programs (CEMI)
21		
22	<u>4.8kV</u>	Hardening
23	Q21.	What is the focus and scope of the 4.8kV Hardening program?
24	A21.	The 4.8kV Hardening program was developed to be a near-term, cost-effective way
25		to improve public safety, by removing arc wire and improving reliability within the

## MEA-11

1 city of Detroit, and surrounding communities by addressing some of the oldest 2 infrastructure in DTE's service territory as quickly as possible. 3 4 This program aligns with the Commission's reaffirmed expectation that the 5 Company remove arc wire, as reflected in the Order No. U-20836, page 94, dated 6 November 18, 2022: "Finally, the Commission clarifies that it finds the removal of 7 DPLD arc wire to be in the interest of customers and supports reasonable and 8 prudent cost recovery for the company's arc wire removal program. While the ALJ 9 is correct that the Commission's order in Case No. U-18484 may not have been a 10 formal directive to remove the arc wire from its territory, DTE Electric's argument 11 that through that order and in Case No. U-18172 the Commission expressed its 12 expectations that the company would do so is also correct." 13 14 The 4.8kV Hardening program was developed as one means to address the aging 15 4.8kV system in the city Detroit, and the surrounding areas. The program's scope 16 is described below: 17 1) Remove Detroit Public Lighting Department (DPLD) arc wire from 18 Company-owned equipment, and ensure the remaining Company wires are 19 left in a safe configuration; 2) 20 Remove DPLD distribution wire from Company-owned equipment when it 21 can be confirmed that the wire is not serving customers; 22 3) Test all utility poles that have Company equipment attached, and replace or 23 reinforce those poles as needed; 24 4) Replace wooden crossarms with fiberglass crossarms;

25 5) Remove service lines to abandoned properties;

Line

No.
M. ELLIOTT ANDAHAZY U-21297		Line
		<u>No.</u>
5) Trim trees, as required, to support construction activities;		1
Perform any additional work necessary as dictated by field conditions; and		2
Remove primary conductor in sparsely populated areas (deconductoring).		3
		4
Can you explain why the Hardening program was developed to remove ar	Q22.	5
wire?		6
The Commission's Order in Case No. U-18484 directed the Company to work with	A22.	7
relevant entities to accomplish a long-term comprehensive plan to address out-of		8
service DPLD owned arc wire.		9
		10
As stated by Company Witness Bruzzano in Case No. U-20162, DTE Electric		11
performed an analysis that considered four alternatives; Full Conversion, Pre		12
Conversion of Overhead Only, Secondary Program, and the 4.8kV Hardening		13
Program. At the time the Company filed Case No. U-20162, the first three option		14
would have taken approximately three times longer, and three times more		15
investment to execute.		16
		17
The Company determined that 4.8kV Hardening was the best option at that time		18
as it was a timely and cost-effective method to remove arc wire. Most of the		19
program's work activities are also requirements to remove arc wire, and the		20
additional hardening activities that are not required for arc wire removal provide		21
customer reliability benefits.		22
		23
		24

#### Line No.

#### 1 Q23. Why does the arc wire removal focused program (4.8kV Hardening) include 2 tree trimming, and pole and pole top replacement? 3 A23. Tree trimming is necessary to gain access to the wire. Testing and replacing, or 4 reinforcing, poles is necessary to make the site safe for workers and the public. 5 Crossarm replacement and rebalancing is likewise necessary, as only removing the 6 arc wire could potentially leave crossarms dangerously unbalanced, and could 7 create hazards. Unbalanced crossarms would occur because arc wire and the 8 Company's overhead lines were originally installed to provide equal force on each 9 side of the crossarm; when the arc wire is removed, the remaining DTE wires exert 10 force on only one side of the crossarm, resulting in the need for the wires to be 11 rebalanced so they are properly supported. 12

# Q24. Per the Commission's Order in Case No. U-20836, what stakeholder engagement concerning 4.8kV circuits was the Company directed to hold in Q1 2023?

### A24. The Company was directed to hold stakeholder engagements in the first quarter of2023 on the following items:

- Complete a full analysis that demonstrates the specific costs of hardening,
   conversion, distributed energy resources (DERs), tree trimming, and/or other
   alternatives compared with the benefits, such as improving safety and
   reducing System Average Interruption Duration Index (SAIDI) and System
   Average Interruption Frequency Index (SAIFI);
- Conduct an analysis of the capabilities/constraints of the 4.8kV system and
   how it affects the use of DERs and electric vehicles (EVs) compared to
   conversion to a 13.2kV system;

#### MEA-14

1		• Complete a full analysis and comparison of alternatives to hardening
2		including, but not limited to, use of DERs and EVs compared to conversion
3		to a 13.2kV system;
4		• Complete a full analysis of optimal reliability-focused distribution
5		technologies, and plan a course of action for arriving at an equitable future
6		for environmental justice and other disadvantaged communities; and
7		• Calculate the miles of arc wire removed to date, the estimated miles of arc
8		wire remaining, the level of confidence that all arc wire is captured in the
9		Company's inventory, the cost of removal with the 4.8kV hardening
10		program, and the cost without the program.
11		
12		At the time of filing this instant case, the Company is in the process of scheduling,
13		and preparing for a technical conference in collaboration with Staff.
14		
15	Q25.	What progress has been made on the 4.8kV Hardening program?
16	A25.	The Company hardened 475 miles in 2022 and expects to harden 345 miles in 2023
17		(Figure 1). The Company expects to have hardened approximately 1,464 miles total
18		from 2018-2023.
19		
20		Approximately 183 circuits, representing 144,222 customers in the city of Detroit,
21		and surrounding areas, have been hardened by the program through year-end 2022.
22		

Line <u>No.</u>



The Company removed 224 miles of arc wire for year-end 2022, and expects to remove 173 miles in 2023 (Figure 2). The Company expects to have removed approximately 695 miles of arc wire total from 2018-2023. The amount of arc wire removed does not match the miles hardened because the Company's asset footprint does not perfectly overlap with the DPLD system.





2

1 Through year-end 2023, the Company expects to have removed approximately 50% 2 of the arc wire that is co-located with DTE owned assets. The Company, using 3 satellite imagery, estimates there will be approximately 770 miles of arc wire colocated with DTE assets remaining after 2023. The remainder of arc wire co-located 4 5 with DTE owned assets is intended to be removed through the 4.8kV Conversion 6 Program discussed in Company Witness Deol's testimony. 7 8 Has the 4.8kV Hardening program benefited customers? **Q26**. 9 A26. Yes. Results show that the 4.8kV Hardening program has been effective in 10 improving the safety, reliability, and resiliency of circuits. The Company reviewed 11 the three-year historic average for reliability and wire downs of the circuits 12 hardened prior to the year hardened, and compared those numbers to the year after 13 hardening was complete. The Company also reviewed the three-year historic 14 average for reliability and wire downs for circuits in the control group (which 15 includes the city of Detroit, and surrounding areas), that were not hardened in that

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All-Weather SAIFI reflects the frequency of the outage events experienced by customers on the circuits regardless of weather conditions. SAIDI Ex-MEDs is an indicator of the amount of time customers are without power excluding the most significant weather event days, such as very large storms. The reduction in the

major event days (Ex-MEDs), and (3) Wire Downs.

time period. The circuits included in this analysis were hardened in 2018, 2019, and

2020. Three key metrics were reviewed to determine the effectiveness of the 4.8kV

Hardening program: (1) All-Weather System Average Interruption Frequency

Index (SAIFI), (2) System Average Interruption Duration Index (SAIDI) excluding

#### **MEA-17**

1 number of wire downs is a measure of the safety improvements for the circuits that 2 were hardened. Figure 3 displays the All-Weather SAIFI improvement of hardened 3 circuits vs. the control group; the hardened circuits experienced a 44% 4 improvement in All-Weather SAIFI, while the control group circuits degraded by 5 26%. Figure 4 displays the SAIDI Ex-MEDs improvement of hardened circuits vs. 6 the control group; the hardened circuits measured a 72% improvement in SAIDI 7 Ex-MEDs, while the control group only experienced a 5% improvement. Figure 5 8 displays the wire down event improvement of hardened circuits vs. the control 9 group; the hardened circuits demonstrated a 26% improvement, while the control 10 group degraded by 20%.

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Figure 3 All-Weather SAIFI Before and After Hardening







Figure 5 Wire Downs Before and After Hardening



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# Q27. What is the Company's plan for future investment in the 4.8kV Hardening program?

8 A27. The Company will have hardened approximately 1,464 miles of circuits by year-9 end 2023. Going forward, the Company will be ramping up work capacity for

1 converting circuits to higher voltages, thus decreasing our investment in the 4.8kV 2 Hardening program, and increasing our investment in the 4.8kV Conversion 3 Program, including in the city of Detroit where arc wire exists and is co-located 4 with DTE assets. The 4.8kV Conversion Program improves public safety, increases 5 system capacity and operability, and supports customer adoption of new 6 technologies such as EVs and DERs. The Company's prioritization of conversions, 7 and consideration of alternatives to the 4.8kV Hardening program were addressed 8 in U-20836, and will be discussed as part of technical conferences, as directed by 9 the Commission, and discussed earlier in my testimony. Details of the 4.8kV 10 Conversion Program can be found in Company Witness Deol's testimony.

11

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### Q28. How can customers stay informed about 4.8kV Hardening work being performed in their area?

- A28. Customers interested in seeing if 4.8kV Hardening work is being performed in their
   respective area can visit the Company's external website at
- 16https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=5d9dc2eb12444561718959ce788086e00e. These maps were developed in 2022 to inform our customers
- 18of the reliability work the Company is performing on their behalf, to visually19display work completed in the last 6 months, and work scheduled to be completed20within the next 12 months. Please note that the 4.8kV Hardening program is called21"Strengthen Power Lines" in the map provided on this website. This map also22shows Tree Trimming, PTMM (called "Utility Poles Maintenance"), and Customer23Excellence (called "Rapid Response"). A current example of this map showing only24the Strengthen Power Lines layer can be seen in Figure 6.

Line <u>No.</u>

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### <u>1 1</u>

#### Figure 6 4.8kV Hardening Map

#### DTE Electric Reliability Improvements Map

Tree Trimming - Tree limbs and branche are responsible for nearly 70 percent of the time our customers spend without power. That's why we're surging our efforts to trim overgrown trees in your neighborhood to keep you safe and the energy grid reliable.

Strengthen Power lines - We're upgrading and strengthening power lines to ensure the electric system in your neighborhood is more resilient and reliable.

✓ Utility Poles Maintenance - We're inspecting and repairing utility poles and replacing cross arms and other pole top equipment to ensure our system delivers the power you need when you need it.

Rapid Response - Tree trimming and pole top equipment repairs/replacements to quickly improve reliability in communities experiencing emergent issues in between planned maintenance schedules.



2

#### 3 Pole and Pole Top Maintenance and Modernization (PTMM)

### 4 Q29. What is the purpose of the Company's Pole and Pole Top Maintenance and 5 Modernization (PTMM) program?

A29. Pole and pole top maintenance programs are basic and necessary to grid reliability,
and an industry standard, similar to tree trimming. Poles and pole top hardware are
the visible, fundamental, and highly exposed parts of the distribution system. Poles
and their associated equipment are subjected to harsh conditions (e.g., ice, heat,
sunlight, and wind), causing them to degrade and weaken over time.

1 Aging poles and pole top hardware increase the risk of failure, which can 2 subsequently cause outages. Examples of incidents that can occur in the event of 3 pole and pole top hardware failures include property damage, fires, and traffic 4 accidents. Additionally, long and costly customer outages can result when this 5 equipment fails unexpectedly, whether from tree impacts or other causes. 6 7 What is the scope of the PTMM program? Q30. 8 A30. The PTMM program identifies damaged or defective poles and pole top hardware, 9 and replaces them prior to failures. Examples of pole top hardware that is replaced 10 include: cracked or broken insulators which can cause pole fires, broken crossarms 11 that can lead to wire downs, and defective equipment that is prone to failures (e.g. 12 cutouts and arrestors with known manufacturer defects). 13 14 This program was called the Pole Top Maintenance (PTM) program in the past, the 15 term "Modernization" was added to the title, and is now called PTMM because the 16 Company has added enhanced specifications in the latter half of 2019. These 17 specifications included changes to the poles and pole top hardware used, and to 18 inspection and testing processes. The enhanced specifications also include 19 replacing old and outdated components, with stronger and more durable 20 components, including higher grades of materials and a more durable design for 21 individual components. 22 23 **Q31.** What are the enhanced pole specifications? 24 A31. Enhanced specifications for poles entail using stronger class 3 poles at a minimum 25 for all distribution circuits, and class 4 poles at a minimum for all secondary circuits

(Table 3). Previously, the specification was to use class 6 poles at a minimum,
which are not as strong as class 3 and 4 poles. As an example, a 35' class 3 pole
has approximately 2x the ultimate tensile strength at groundline, and approximately
20% more strength against wind bending at groundline, when compared to a 35'
class 6 pole. More detail on the enhanced pole specifications can be found in
Exhibit A-23, Schedule M8.

'

8		Table 3Pole Speci	fications
	Equipment	Prior Construction Specifications (Before 2019)	Current Construction Specifications (2019-Current)
	Poles	• Class 6 poles minimum	<ul><li>Class 3 poles minimum for distribution</li><li>Class 4 poles minimum for secondary</li></ul>

9

#### 10 Q32. What are the enhanced pole inspection specifications?

11 A32. The Company's previous pole inspection specification required physical testing on 12 poles 40 years and older. The Company's new pole inspection specification 13 requires testing for below-grade decay that impacts the integrity of the pole, and 14 treatment to prevent the spread of the decay, on poles that are 20 years and older 15 (Table 4). This change was made after benchmarking other utility practices (Table 16 5), reviewing the U.S. Department of Agriculture's Rural Utility Services (RUS) 17 bulletin ("1730-121 USDA Rural Utility Service Wood Pole Inspection and 18 Maintenance"), and the Company's pole failure performance. The RUS 19 recommends that utilities in Michigan perform the first test for pole decay within 20 10-12 years of installation, and subsequent tests to occur every 10 years thereafter. 21 The Company adopted testing for poles 20 years and older after reviewing the

No. 1 above sources, reviewing its own pole performance, and determining that below 2 grade pole decay has rarely been seen on poles installed less than 20 years in the 3 past. 4 5 Poles are either replaced, or reinforced, based on specific criteria shown in Section 6 4 of Exhibit A-23 Schedule M8 Wood Pole Maintenance Specification. 7 8 Table 4 **Pole Testing** 

Equipment	RUS (Rural Utility Services)	DTE Old Specification	DTE New Specification
Pole	Physical testing on all poles	Physical testing on all poles	Physical testing on all poles
Inspections	10+ years old	40+ years old	20+ years old

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Table 5

#### Utility Pole Benchmarking

	Company 1	Company 2	Company 3	Company 4
	Northeast	Northeast	Midwest	Midwest
Inspection Practices	4-year pole and pole top inspection program	5-year pole and pole top visual inspection program	10-year pole test program 5-year visual inspection including pole top	10-year pole test program 5-year pole top inspection program

11

#### 12 Q33. What are the enhanced pole top hardware specifications?

A33. Previously, the PTMM program would replace old pole top hardware withhardware of the same type. The enhanced specification calls for modernizing

1 equipment, which includes replacement of damaged wood crossarms with 2 fiberglass crossarms, porcelain cutouts with polymer cutouts, and porcelain 3 insulators with polymer clamp-top insulators (Table 6). Fiberglass crossarms have 4 five times the mechanical strength compared to their wood counterparts, and 5 polymer equipment has six times the mechanical strength of its porcelain 6 counterparts. These new materials will result in less failures in adverse conditions, 7 such as during high winds and storms, experience less deterioration from rain and 8 sun exposure, and are in line with the other strategic investments the Company is 9 making in the grid to improve customer reliability. The Company reviews these 10 specifications bi-annually (or more often if necessary), and makes changes as 11 appropriate based on internal performance analysis and industry best practices.

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13The current criteria by which pole top equipment is evaluated is provided in Exhibit14A-23 Schedule M9 Pole Top Maintenance Specification, which provides15specifications and visual examples of what is considered defective pole top16equipment.

17 18

 Table 6
 Pole Top Hardware Equipment Specifications

Equipment	Prior Construction Specifications (Before 2019)	Current Construction Specifications (2019-Current)
Crossarms	• Wood crossarms (35-year lifespan)	• Fiberglass crossarms (stronger, 60-year lifespan)
Insulators	Porcelain insulator	• Polymer insulator (stronger, longer lasting)
Cut-outs	Porcelain cut-outs	• Polymer cut-outs (stronger, longer lasting)

Line No.

- 1
- 2 Q34. Why has the Company increased investments in PTMM?

3 A34. Based on new PTMM/4.8kV Hardening inspection, testing, and construction 4 specifications, the amount of work required per circuit mile increased compared to 5 prior years, as seen in the increase in poles and pole top hardware locations (poles 6 where only the hardware was replaced, not the pole) replaced per circuit mile in 7 Table 7 and Table 8. The Company did not track pole top hardware location data 8 in an easily analyzed format in prior years, and therefore Table 7 displays sample 9 data from 449 contractor circuit-level scope documents for the years 2018-2022. 10 The Company has on average approximately 35 poles per circuit mile. During 11 2018-2021, the average pole tops replaced per circuit mile was 1.6, whereas in 2022 12 the average was 3.6. This is a 2.3x increase in pole top locations replaced per circuit 13 mile driven by the more robust PTMM/4.8kV Hardening inspections. The 14 Company has begun tracking pole top hardware replacement locations in a 15 centralized database beginning in 2023. The Company did track poles replaced on 16 its internal scorecard, and analyzed this dataset to demonstrate the increase in poles 17 replaced per circuit mile. During 2018-2021, the average poles replaced per circuit 18 mile was 1.1, whereas in 2022 the average was 2.9 (Table 8). This is a 2.5x increase 19 in poles replaced per circuit mile. These increases in poles and pole top hardware 20 locations replaced per circuit mile are the driver of increased investments in 2022.



#### **Circuit Mile (Sample Analysis)**

	2018	2019	2020	2021	2018-2021 Average	2022
Pole Top Locations per Circuit Mile	1.6	1.2	1.2	2.1	1.6	3.6

#### Table 8

#### e 8 PTMM Poles Replaced per Circuit Mile

	2018	2019	2020	2021	2018-2021 Average	2022
Poles Replaced per Circuit Mile	1.6	1.3	1.0	0.7	1.1	2.9

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Figure 7 and Figure 8 demonstrate a financial analysis of the average PTMM investment for work completed in 2018-2021 compared to 2022. All the charts show an increase in investment supporting the data in Table 7 and Table 8, thus an increase in work completed per circuit mile.

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#### Figure 7 PTMM Capital Investments and Poles Replaced

**Figure 8 PTMM Contract Labor and Materials** 





Line <u>No.</u>

	<b>M. ELLIOTT ANDAHAZY</b> U-21297
Q35.	What processes or programs have been used historically to meet the 10-12 year
	pole inspection target?
A35.	The Company has targeted to inspect poles on a 10-12-year cycle, as recommended
	by the MPSC Staff in the "Utility Pole Inspection Investigation Report" published
	on November 20, 2009, and has historically achieved this objective leveraging the
	following inspection processes as shown in Figure 9:
	1. Physical pole tests from PTMM and 4.8kV Hardening programs
	2. Visual pole and pole top inspections from the PTMM and 4.8kV
	Hardening programs

103. Visual inspections from the Joint Use process

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- 4. Poles replaced on emergent trouble and storm
  - Figure 9 Pole Inspections



#### Pole Inspections

(Thousands, 2017-2021 Actual, 2022 Estimated)

Line No.

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#### Q36. What changes has the Company made to its inspection processes?

2 A36. The Company discontinued using Joint Use inspections to reach the 10-12 year 3 cycle target in 2022. Joint Use inspections are less comprehensive visual 4 inspections that do not directly address pole top hardware, and are mainly intended 5 to ensure there is proper clearance between utility and telecommunication lines. 6 Instead, in 2022, the Company began exclusively utilizing the PTMM, 4.8kV 7 Hardening, and 4.8kV Conversion programs for pole and pole top hardware 8 inspections. This has resulted in a greater number of inspections performed by the 9 PTMM program in 2022 than in prior years, at the new enhanced specifications 10 discussed earlier. The Company intends to continue this change in inspection 11 process going forward as it will benefit our customers.

12

### Q37. How has the workload changed after enhancing specifications, and increasing the quantity of inspections performed by the PTMM program?

A37. The recent focus on adhering to the pole inspection cycles, combined with the more robust inspection specifications, has resulted in an increase in pole and pole top hardware locations identified. Historical PTMM funding levels were not sufficient to construct all work identified by these inspections in a timely manner, thus the Company incurred a backlog of pole and pole top hardware locations to be replaced.

20

#### 21 Q38. What work is in the PTMM backlog and work-in-process (WIP)?

A38. Table 9 displays a snapshot of the PTMM pole backlog, including 1,517 poles
identified before 2022, and the current 3,178 work-in-process (WIP) poles
identified for replacement in 2022. Table 10 displays the pole top hardware
location backlog, including 7,757 units of pole top hardware needing replacement

identified before 2022, and the current 6,897 units of WIP pole top hardware locations identified for replacement in 2022. There can be multiple units of pole top hardware at each pole top location. Examples of units for pole top hardware include crossarms, insulators, and cut-outs.

**Inspection Year** Un-2016 2017 2018 2019 2020 2021 2022 Total Known Poles to 300 39 8 44 325 12 790 3,178 4,695 Replace

Table 9PTMM Pole Backlog & WIP as of 1/6/2023

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Table 10PTMM Pole Top Hardware Backlog & WIP as of 1/6/2023

	Inspection Year										
	Un- Known	2016	2017	2018	2019	2020	2021	2022	Total		
Pole Top Units to Replace	1,402	4	5	475	2,045	17	3,810	6,897	14,654		

9

#### 10 Q39. What work did the PTMM program complete in 2022?

- 11 A39. The PTMM program modernized 1,562 circuit miles, replaced 4,537 poles, and
- 12 performed approximately 92,000 inspections in 2022.
- 13
- 14

1	Q40.	What is in the Company's 2023 and 2024 PTMM workplan?
2	A40.	The 2023 PTMM workplan includes replacing poles and pole top hardware on
3		approximately 1,000 circuit miles, replacing approximately 3,300 poles (which
4		includes eliminating the pre-2022 condemned pole backlog), and performing
5		approximately 50,000 inspections on circuits to be modernized in 2024. Based on
6		my earlier testimony, the Company expects that poles and pole top hardware per
7		circuit mile will continue to be higher. The amount of PTMM inspections planned
8		for 2023 is less than 2022 because the program is focusing on eliminating pre-2022
9		backlog, and does not want to inspect more work than it can construct in a timely
10		manner.
11		
12		The 2024 PTMM workplan includes modernizing approximately 2,000 circuit miles,
13		replacing approximately 6,200 poles, and performing 87,000 inspections.
14		
15	Q41.	How will these increased investments in the PTMM program benefit
16		customers?
17	A41.	Increased investments in the PTMM program will allow the program to achieve a
18		10-year cycle of pole and pole top hardware inspections which are based on a more
19		rigorous approach, and to replace all poles and pole top hardware that fail testing
20		and inspection within one year of testing and inspection. Absent this investment in
21		the PTMM program, the poles and equipment identified in the backlog above will
22		fail at some point, causing customer outages. Ramping up the PTMM program will
23		reduce equipment related outages, just as the line clearance program has done to
24		reduce tree related outages (as discussed in Company Witness Hartwick's
25		testimony). The Company is targeting to reach the annual work volume necessary

Line <u>No.</u> to reach this cycle by the end of 2025, provided it gains approval for necessary investment levels. This cycle would reduce Overhead (OH) equipment failures on the system.

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5 OH equipment failures account for almost 25% of all outage events. As a result of 6 executing the planned improvements to the PTMM program, the Company expects 7 to see a further reduction in equipment related outage events that will drive 8 reliability improvements, reducing reactive and storm expenditures, and improve 9 the safety of the system by reducing wire downs and pole failures on the circuits 10 for which the Company is able to complete pole and pole top hardware 11 replacements.

12

Later in my testimony, I describe a new process for identifying poor performing circuits called the Pre-Storm Season Strengthening process. In 2022, 12 circuits were identified through this process, and completed through the PTMM program prior to the summer storm season. Figure 10 displays the improvements in reliability the affected customers experienced during peak storm months following this construction. This is further support demonstrating tangible customer benefits obtained due to the PTMM program.



Line

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### Q42. How can customers stay informed about PTMM work being performed in their area?

4 Customers interested in seeing if PTMM work is being performed in their A42. 5 respective website area can visit the Company's at https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=5d9dc2eb1244456 6 7 18959ce788086e00e. These maps were developed in 2022 to inform our customers 8 of the reliability work the Company is performing on their behalf, to visually 9 display work completed in the last 6 months, and work scheduled to be completed 10 within the next 12 months. Please note that the PTMM program is called "Utility 11 Pole Maintenance" in the map provided on this website. This map also shows Tree 12 Trimming, 4.8kV Hardening (called "Strengthen Power Lines"), and Customer 13 Excellence (called "Rapid Response"). A current example of this map showing only 14 the Utility Pole Maintenance layer can be seen in Figure 11.

Figure 11

РТММ Мар

### DTE Electric Reliability Improvements Map 9 nd address or plac Tree Trimming - Tree limbs and branches are responsible for nearly 70 percent of the time our customers spend without power. That's why we're surging our efforts to trim overgrown trees in your neighborhood to keep you safe and the energy grid reliable. ∷ . ♦ 0 Strengthen Power lines - We're rading and strengthening power lines to ure the electric system in your phoorhood is more resilient and reliable. Utility Poles Maintenance - We're MP inspecting and repairing utility poles and replacing cross arms and other pole top equipment to ensure our system delivers power you need when you need it. Rapid Response - Tree trimming and pole top equipment repairs/replacements to quickly improve reliability in communities experiencing emergent issues in between planned maintenance schedules. Portag inasville

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#### 3 Inspection Costs

## 4 Q43. What is the purpose of Exhibit A-12, Schedule B5.4.8 related to 4.8 kV 5 Hardening and PTMM details?

A43. Pursuant to the Order in Case No. U-20836 (page 471), the Company was directed
to provide a thorough breakdown of total pole inspection and testing costs applied
across all capital programs. Pole inspection and testing costs are included within
two projects on page 8 of Exhibit A-12, Schedule B5.4: 4.8 kV Hardening (line
10 12) and PTMM (line 13). The purpose of Exhibit A-12, Schedule B5.4.8, is to

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provide a breakdown of the costs within these two programs in order to show the inspection and testing costs. Lines 1 through 5 provide the breakdown of 4.8 kV Hardening program, while lines 6 through 11 provide the breakdown of PTMM. Inspection and testing costs are shown on line 2 for the 4.8 kV Hardening program and line 7 for the PTMM program.

6

7 As discussed by Company Witness Uzenski, the Company is updating its 8 capitalization policy effective January 1, 2023, to no longer capitalize pole 9 inspection and testing costs associated with the PTMM program. There are no 10 inspection costs starting in 2023 for the 4.8 kV Hardening program on Line 2 since 11 final inspections were completed in 2022. However, there are \$3M and \$5M of 12 inspection costs included in 2023 and 2024, respectively, for the PTMM program 13 as shown on Line 7. These amounts are being removed from capital expenditures 14 in 2023 and 2024 on Line 12. This also results in an increase in O&M in the 15 projected period of \$5M, which Company Witness Robinson has included in 16 Exhibit A-13, Schedule C5.6.

- 17
- 18 Cable Replacement Program

#### 19 Q44. What is the purpose of the Company's Cable Replacement program?

A44. Cable replacement is an industry standard program supporting reliability.
 Underground (UG) system cable is a critical component of the subtransmission and
 distribution systems. While underground cable provides a higher resiliency to
 storms than comparable overhead lines, a failure can interrupt a large number of
 customers for an extended period of time. UG cables are more difficult to locate
 and repair than overhead circuits. When an UG cable fails, the customers fed from

1 that circuit are moved to a redundant, or back-up cable, to restore power, and remain 2 on the alternate circuit until the original cable is replaced and back in service. The 3 process to replace the cable includes locating the fault, cutting down the failed 4 section(s), pulling the failed cable out of the conduit, installing new cable, 5 reconnecting (splicing) the new cable to the existing circuit, and energizing the 6 circuit. While these steps are in process, the system has lost redundancy and has 7 increased risk for longer duration outages (if a failure occurs on the redundant 8 circuit). Cable failures can also cause failures in other equipment, including 9 adjacent cables and switchgear, which can then impact an even larger number of 10 customers for a longer period of time.

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12 As an example of a critical system cable failure, in 2022 the Company had back-13 to-back cable failures in eastern Detroit where both cables fed common substations. 14 The first cable failure resulted in approximately 3,000 customer outages, and approximately four hours later a second cable failure resulted in an additional 15 16 approximately 8,000 customer outages. These cable failures, and resulting customer outages, occurred in July when the system experienced peak loading, 17 18 making it impossible to shift this customer load to other cables. The loss of 19 redundancy resulted in the restoration of these customers being extended, with all 20 customers being restored 12 hours after the failure. This restoration was 21 accomplished by temporarily transferring customer load to other equipment on the 22 system, including the deployment of on-site generators, until final cable repairs 23 could be made. If underground cable redundancy had been maintained on the 24 system, the customers could have been restored in less than half the time.

1 During this type of emergent restoration, the crews may experience multiple 2 challenges, which can complicate the work or slow progress on remediation of the 3 failure. In some instances, field crews find underground ducts have collapsed on 4 the cables, making the cable extremely difficult, or impossible to replace before the 5 ducts are repaired. Safety concerns during restoration sometimes cause other intact 6 cables to require a shutdown, meaning they must be de-energized from the 7 substation to make the site safe for work. Other examples of safety concerns include 8 pumping water out of the manholes and managing the contaminated water, ensuring 9 the air quality is safe for entry, and often including remediation of contaminants. 10 Once the manholes can be entered safely, the work includes inspecting and testing 11 long stretches of cable to find the fault, and identification of adjacent hazards. 12 Finally, the crews typically pull and splice the cable as described above, which can 13 be difficult during an emergent situation.

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15 Different types of cables are known for specific failure modes. XLPE (cross-linked 16 polyethylene) cable manufactured before 1990 has a design defect that leads to 17 premature insulation breakdown and failures (also called "treeing") and has 18 contributed to switchgear failures (switchgear is further explained in the DGP). Gas 19 cable (cable that has cavities within the insulating layer that are filled with nitrogen 20 gas under pressure) is an obsolete design, that is prone to mechanical damage that 21 leads to leaks and failures and costly repairs. As detailed in the DGP, Exhibit A-23, 22 M7 (as supported by Company Witness Robinson), section 8.16.3 on page 202, 23 more than 57% of the Company's system cable is beyond typical life expectancy. 24 While age is not the only factor to determine a need for replacement, based on the 25 Company's experience, failure rates increase significantly with age.

#### **MEA-38**

1 Table 11 shows the average age of the different types of system cable on the 2 Company's distribution and subtransmission systems. The typical life expectancy 3 of system cable is 35 to 40 years, although actual useful life varies depending on 4 cable type and field conditions. Based on its asset health assessment for system 5 cable, the Company has determined that approximately 30% of its system cable is 6 at-risk cable and a candidate for replacement, including XLPE cable manufactured 7 before 1990, gas cable, VCL (varnished cambric lead), and paper-insulated-lead 8 cable (PILC) cable greater than 60 years in age. Through its Global Prioritization 9 Method (GPM) model, the Company has confirmed the priority of its Cable 10 Replacement Program, which is ranked No. 28.

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 Table 11
 Cable Type Summary with Average Age and Life Expectancy

Cable Type	PILC	EPR	VCL	Gas	XLPE Post-1990	XPLE Pre-1990	Butyl
Miles	2,365	570	125	55	35	69	35
% of Total Population	73%	18%	4%	1%	1%	2%	1%
Average Age	50	16	59	54	20	36	52
Life Expectancy	40	35	40	40	40	25	20

13

The Company's cable assets have an elevated failure risk that will increase as the installed cable sections continue to age. A system cable failure can have a significant impact on the overall system and customer reliability, because when a cable fails it reduces the level of redundancy in the system itself. An acceleration in cable failures with simultaneous failures of multiple cables across the system,

1 could lead to very lengthy outages, and a mix of new and existing cable scattered 2 throughout the system (based on the reactive replacement of failed cable). Planned 3 replacement of UG system cable allows the Company to proactively target cable at 4 high risk of failure. This allows for a more strategic, and more efficient process to 5 replace large portions of cable in order to reduce the risk of failures and increase 6 redundancies in a given area. 7 8 **Q45**. What is the scope of the Cable Replacement Program? 9 A45. The Cable Replacement program exists to prioritize, and perform planned system 10 cable replacements. Cable replacement prioritization is based on multiple factors 11 including cable type, vintage, failure history, system impacts, and cable loading. 12 These cables are installed in conduit and spliced together in manholes. System cable 13 is needed when routing multiple circuits through congested areas, such as when 14 entering or exiting a substation, and in heavily urbanized areas. When replacing 15 system cable, the Company will also replace failed/collapsed conduit, ducts, and 16 manholes, upgrade substation cable positions, and rebuild cable poles as necessary. 17 18 **Q46**. How does the Company plan to execute the system cable replacement 19 program? 20 A46. The Company has implemented multiple changes to increase its ability to execute 21 the system cable replacement program. A dedicated organization was created 22 focused on underground work, and has been building execution capacity and 23 updating work processes to prepare for the needed levels of cable replacement. An 24 example of a process improvement includes adding a pre-construction inspection 25 process for duct runs to identify any collapsed ducts or hazards before cable work

#### **MEA-40**

1		begins. This allows the Company to schedule infrastructure repair work before
2		cable work has begun, which increases program efficiency. The Company has
3		increased its workforce of cable splicers by 17% over the last 6 years to expand
4		annual work capacity. In addition, the Company has developed partnerships with
5		engineering, design, project management, and construction firms that have
6		successfully helped other utilities build their cable replacement programs to
7		significant levels. Further details on how the Company has increased overall work
8		capacity to meet increased investment plans can be found in Company Witness
9		Miller's Testimony.
10		
11	Q47.	How much system cable replacement is planned for 2023-2024?
12	A47.	The Company replaced 4.9 miles of system cable in 2022, and is targeting
13		approximately 17 miles in 2023, and 19 miles in 2024.
14		
15		The increase in miles forecasted for 2023 and 2024 is partially explained by pre-
16		work and cable partially installed in 2022 that do not appear in 2022 replacement
17		metrics, as the program only records cable as completed in the tracking metric after
18		newly installed cabled is energized, and all old cable is removed from service. In
19		planning for miles of replacements, it should be noted that the cost and complexity
20		of miles can vary depending on the type of cable used and the field conditions,
21		including collapsed ducts and other conduit issues, hazards in manholes, and
22		shutdown constraints.
23		
24		Each year's plan and budget also include funding to complete design for the

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25 following year's program, remediation of identified hazards to streamline execution

#### MEA-41

Line No. 1 of the following year's plan, and conduit repair/construction so that execution of 2 cable replacement can proceed with few work interruptions. 3 4 **O48**. How does the Cable Replacement program benefit customers? 5 A48. Replacing system cable improves reliability for customers. The underground cable 6 system is designed with multiple redundancies to ensure customer reliability. While 7 single cable failures do not normally result in customer outages, if the primary and 8 redundant cables fail at the same time, it results in prolonged outages for customers. 9 Some types of industrial class customers such as hospitals, aren't able to tolerate 10 the risk of running with a single cable, and therefore reduce or shut down some 11 functions when this happens. This program reduces overall risk to customers and 12 the grid by proactively replacing cables before they fail, in order to ensure 13 necessary redundancies for this critical part of the system as designed. Fewer 14 system cable failures will also result in a reduction in reactive expenditures because 15 planned replacements are more efficient than repeated, unplanned, reactive 16 replacements as described in the example given earlier in my testimony. 17

#### 18 Underground Residential Distribution (URD) Replacement Program

## Q49. What is Underground Residential Distribution (URD) Cable, and what is the purpose of replacing it?

A49. All residential subdivisions in the Company's service territory, built since the early
1970s, are served with URD cable instead of overhead lines. There are two primary
types of URD cable, and 1985 is a demarcation point in manufacturing practices;
Pre-1985, the insulation in URD is XLPE (non-tree retardant), and post-1985 the
insulation is TR-XLPE (tree-retardant). In cable insulation, "treeing" refers to the

1 tree-like pattern of insulation breakdown. The breakdown typically originates at 2 an impurity or defect in the solid insulation, and grows gradually over time to 3 resemble the branches of a tree, ultimately leading to a cable failure. There are 4 approximately 11,000 total miles of URD cable on the system, with approximately 5 2,100 miles (19%) being pre-1985 vintage. 6 7 In addition to failures caused by treeing described above, in general, the rate of 8 URD cable failures increases with the age of the cable, and the rate further increases 9 once a cable experiences its first failure. For the five-year period from 2018 through 10 2022, there were on average approximately 1,000 URD feeder cable failures per 11 year as seen in Table 12.

Table 12URD Cable Failures

	2018	2019	2020	2021	2022	2018-2022 Average
URD Cable Failures	1,039	755	1,036	986	900	943

13

12

URD replacement is an industry standard program, and is important to maintain the
health of the grid, and reduce the risk of cascading failures which would lead to
lengthy customer outages and increasing reactive replacement expenditures.
Through its Global Prioritization Method (GPM) model, the Company has
confirmed the high priority of its URD Replacement Program, which is ranked No.
19

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#### 1 Q50. What is the scope of the URD Cable Replacement Program?

2 A50. There are two primary types of work performed by the URD Cable Replacement 3 program: prioritizing and replacing existing URD cable, and replacing live-front 4 transformers (described below). The program prioritizes and replaces URD cable 5 based on multiple factors including age, vintage, number of failures, and number 6 of customers affected by those failures. The program also includes the replacement 7 of live-front transformers with dead-front transformers. Live-front transformers 8 have no protective coverings over energized equipment, and therefore pose a 9 potential safety risk to crews in the field while performing operating work once the 10 external transformer covering is removed.

11

### Q51. What is driving the planned increase in investments for the URD Cable Replacement?

14 A51. For most types of URD cable installed, the manufacturer's expected useful life is 15 40 years. A proactive 40-year replacement cycle would require 276 miles of URD 16 to be replaced annually. The Company has been increasing its capacity to execute 17 this work in recent years and is continuing to increase its capacity (Table 13) to 18 levels above the 2018 investment. Approximately 1,879 miles, or 17% of the total, 19 of the Company's URD cable is currently at, or beyond the manufacturer's expected 20 useful life. Increasing investments in the URD Cable Replacement program reduces 21 the risk of increasing failures due to aging URD cable.

#### Line <u>No.</u>

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				-		
	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
URD Miles Replaced	4	4	25	45	80	87

**URD Miles Replaced** 

Table 13

3 As discussed above, pre-1985 vintage, non-tree retardant URD cable, URD cable 4 older than the manufacturer's recommended useful life, and URD cable that has 5 experienced failure in the past, are more prone to failure. These factors all 6 contribute to URD failures which cause residential customer outages. These 7 outages are typically restored quickly after an Underground (UG) splicing crew 8 arrives and bypasses the URD failure by back feeding the customers from another 9 source on the URD loop. However, once the customers are restored, there is follow-10 up work required to repair the URD cable fault that caused the original outage, and 11 to restore the system to normal operating conditions, which provides system 12 redundancy. This follow-up work is called an open loop. These open loops leave 13 the system without redundancy, so if a second URD failure occurs on the same 14 URD loop, a new long-duration outage (12+ hours) will result for the customers as 15 there is no redundancy to back feed the customers as described above, while 16 replacing the failed URD cable. Maintaining the queue of open loops at a low level 17 reduces the likelihood of extended customer outages when a failure on the URD 18 loop occurs. In addition, planned replacements are more cost effective than 19 repairing failures, as the Company can strategically plan to replace entire circuits

<sup>2</sup> 

of URD and live-front transformers, rather than reactively fixing smaller sections
 of the circuit following a failure.

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### 4 Q52. Does the Company have the resources to replace the targeted URD cable 5 miles?

6 A52. Yes. The Company has been successful in ramping up its URD Replacement 7 program in recent years (as seen in Table 13). This is because the Company has 8 increased the splicer workforce by 17% in the last 6 years, improved material 9 sourcing practices, built partnerships with third parties that have executed very 10 large-scale replacement programs, and increased internal oversight and 11 coordination through the PMO. Further details on how the Company has increased 12 overall work capacity to meet increased investment plans can be found in Company 13 Witness Miller's Testimony.

14

#### 15 Q53. How much URD cable replacement is planned?

16 A53. The program replaced 45 miles in 2022, and in ramping up the program, expects to 17 replace 80 miles in 2023, and 87 miles in 2024. These investments include design 18 for the following year's program, remediation of identified hazards to streamline 19 execution of the following year's plan, the replacement of the targeted URD miles, 20 and the replacement of live-front transformers with dead-front transformers. The 21 Company is evaluating how to continue to increase investment in this program, and 22 the current plan can be found in its Exhibit A-23 Schedule M7 DGP supported by 23 Company Witness Robinson filed on 9/30/2021 in Case No. U-20147, included as 24 Exhibit A-23, Schedule M-7 in the instant case.

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#### Q54. How does the URD Cable Replacement program benefit customers?

A54. The program will improve reliability by reducing the number of residential
customer interruptions experienced by URD cable failures in the areas in which this
program has completed work. This will also benefit customers by reducing the risk
of multiple failures, and long duration outages due to pre-existing open loops as
described above.

7

#### 8 Breaker Replacement Program

#### 9 Q55. What is included in the Breaker Replacement Program?

10 A55. The company has approximately 6,000 breakers on the electrical distribution and 11 subtransmission systems with approximately 60% of those breakers being beyond 12 their life expectancy. A circuit breaker is an electrical switch designed to isolate 13 faults that occur on substation equipment, buses, or circuit positions. Its basic 14 function is to interrupt current flow after a fault is detected to minimize equipment 15 damage due to high fault currents, and to isolate the faulted asset from the electrical 16 system. The breakers included in the replacement program are obsolete breakers, 17 typically utilizing insulation oil for fault extinguishing. These breakers are 18 classified into four categories: distribution breakers, subtransmission breakers, H-19 breakers, and substation reclosers. In addition to replacing breakers, the program 20 also replaces relays and controls to enable SCADA (supervisory control and data 21 acquisition) utilization on equipment, to give the Electric System Operations Center 22 (ESOC) greater visibility to system performance.

- 23
- 24
- 25

1	Q56.	What are the customer benefits from the Breaker Replacement Program?		
2	A56.	The benefits of breaker replacement and enhanced relaying and controls include		
3		enhanced safety, reduction of substation outage risk caused by breaker failures,		
4		improved customer reliability, reduction in reactive expenditures due to breaker		
5		failures, added ability to utilize SCADA controls, and the reduction of outage		
6		duration due to enhanced fault location and event analysis provided by SCADA		
7		capability.		
8				
9	Q57.	How are breakers selected for replacement?		
10	A57.	The candidates for breaker replacements are chosen to maximize the above listed		
11		benefits. Breakers are prioritized based on the following criteria:		
12		- Breakers with no or limited availability of spare parts		
13		- Breakers with insulation oil for fault interrupting medium which is		
14		flammable		
15		- Breakers that require short inspection cycles compared to the rest of the		
16		breakers on our system		
17		- Breakers with known performance issues		
18				
19	Q58.	How many Breakers have been replaced through the Breaker Replacement		
20		program in 2022 and prior years?		
21	A58.	Please see Table 14.		
#### 1

Breaker Type	2018	2019	2020	2021	2022
Distribution Breakers	31	19	20	22	15
Subtransmission Breakers	14	9	7	4	12
H-Breakers	5	7	6	3	2
Substation Reclosers	6	7	4	10	5
Total Breakers	56	42	37	39	34

**Breakers Replaced** 

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#### 3 Q59. How many Breakers does the Company plan to replace in 2023 and 2024?

Table 14

4 A59. The Company plans to replace 35 breakers in 2023 and 36 breakers in 2024.

5

#### 6 Frequent Outage Programs (CEMI)

#### 7 Q60. What programs are included in Frequent Outage Programs?

A60. There are three primary programs under Frequent Outage Programs: Customer
Excellence (CE), Frequent Outage (CEMI), and Strategic Reliability Improvement
Program (SRIP).

11

12 The CE program was established to provide rapid solutions to small pockets of 13 customers experiencing poor reliability. These customers are identified as 14 experiencing four sustained outages (SAIFI > 4.0), or nine momentary outages 15 (MAIFI > 9.0) per year. The prioritization method for the CE program relies on 16 Advanced Metering Infrastructure (AMI) data to identify these customers on a rolling 12-month basis to address issues more rapidly than other programs which rely on the annual analysis of reliability events. In addition to reliability event data, the prioritization also includes an evaluation of the time since the area's last tree trim was completed, any other planned work on the circuits, and customer complaints.

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7 Upon identification of a circuit that meets the CE prioritization criteria, the 8 Company conducts a field patrol to understand both equipment and tree conditions. 9 After the patrol, the scope of work is developed for both equipment-related and 10 tree-related problems identified. In addition to the defective equipment 11 replacements and tree trimming, the scope of work also includes checking operating 12 equipment to ensure it is functioning properly, conducting fault studies to ensure 13 fuses are properly sized, and installing additional equipment, such as reclosing 14 devices and animal guards, to prevent future outages. On average, the solutions 15 require investments between \$60,000 and \$80,000 per circuit to implement.

16

17 The Frequent Outage program, also known as the CEMI (Customers Experiencing) 18 Multiple Interruptions) program performs improvements to either portions of a 19 circuit (customer pockets), or entire circuits as appropriate. The primary 20 distinctions between the CE and the CEMI programs are that circuits are normally 21 selected for the CEMI program based on three-year average circuit SAIDI and 22 SAIFI performance, MPSC complaints, and regional expertise on customer needs. 23 In addition, the scope of work performed under the CEMI program is more 24 comprehensive, and typically requires investments between \$250,000 and 25 \$300,000 per circuit to implement.

No. 1 Strategic Reliability Improvement Program (SRIP) is a new program which began 2 as an outcome of the Pre-Strom Season Strengthening process, as described later in 3 my testimony. 4 5 Q61. Why did the level of investment in the Frequent Outage Programs increase in 6 2022? 7 A61. The increase in Frequent Outage program investments is primarily driven by 8 increased work identified with a new process called the Pre-Storm Season 9 Strengthening process, as defined in detail in Company Witness Hill's testimony. 10 Following the storm season of 2021, the Company identified 527 circuits through 11 the Pre-Storm Season Strengthening process that required some sort of work to be 12 completed to improve customer reliability. Of this total, 262 circuits were assigned 13 to the CE program based on the scope of work needed. These circuits were 14 completed prior to the 2022 storm season (75 in fall 2021, and 187 in winter/spring 15 2022), and were the driver behind the more than 40% increase of total CE circuits 16 completed from 2021 to 2022.

17

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## 18 Q62. Why is the investment in the Frequent Outage program still elevated in 2023 19 and 2024?

A62. As mentioned above, in the fall of 2021, the Company utilized the new Pre-Storm
Season Strengthening process to identify 527 circuits that required different scopes
of work to improve reliability. Of this total, 84 were assigned to the System
Improvements program. For these circuits, the regional engineering teams
evaluated the scope of work required, engineered and designed the jobs, and
worked with the PMO to complete the work prior to the 2022 storm season (2 in

<u>NU.</u>		
1		fall 2021, and 82 in winter/spring 2022). This increase in System Improvements
2		investment is described in Company Witness Hill's testimony. As the Company
3		evaluated the work completed, the decision was made to move this investment from
4		the System Improvements program to the Frequent Outage program in 2023 and
5		beyond, as the third primary program under the broader Frequent Outages (CEMI)
6		program, and this scope of work is called the Strategic Reliability Improvement
7		Program (SRIP).
8		
9	Q63.	Have circuits been selected through the Pre-Storm Season Strengthening
10		process for 2022-2023 and 2023-2024?
11	A63.	Yes. In the fall of 2022, the Company analyzed the performance data of circuits
12		following the Pre-Storm Season Strengthening process, and identified circuits that
13		would benefit from reliability work using the defined selection process. The
14		Company has created a circuit plan for both 2022-2023 and 2023-2024.
15		
16		The 2022-2023 Pre-Storm Season Strengthening plan includes 385 total
17		distribution circuits and 13 subtransmission circuits. Of these, 182 distribution and
18		3 subtransmission circuits were assigned to the CE program, and 72 distribution
19		circuits and 9 subtransmission circuits were assigned to SRIP. Of these, 40 circuits
20		were completed in the fall of 2022, and 131 are anticipated to be completed between
21		January and June of 2023.
22		
23		The 2023-2024 Pre-Storm Season Strengthening plan includes a total of 427
24		circuits. If additional circuits need to be added to the list after assessing 2023 storm

## **MEA-52**

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	<b>M. ELLIOTT ANDAHAZY</b> U-21297
	performance, the Company will make the appropriate adjustments to the 2023-2024 plan.
Q64.	Has the work performed by Frequent Outage Programs through the Pre-
	Storm Season Strengthening process been effective?
A64.	Yes. Circuits that were identified in the 2022 Pre-Storm Season Strengthening
	process and assigned to Frequent Outage Programs, saw a 69% reduction in All
	Weather SAIFI in 2022, as compared to 2021 during the peak storm months of June
	through September (Figure 12).

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Figure 12Frequent Outage Pre-Storm Season Strengthening



All Weather SAIFI

# Q65. How can customers stay informed about Customer Excellence work being performed in their area?

3 A65. Customers interested in seeing if Customer Excellence work is being performed in 4 respective area can visit the Company's external website their at 5 https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=5d9dc2eb1244456 6 18959ce788086e00e. These maps were developed in 2022 to inform our customers 7 of the reliability work the Company is performing on their behalf, to visually 8 display work completed in the last 6 months, and work scheduled to be completed 9 within the next 12 months. Please note that the Customer Excellence program is 10 called "Rapid Response" in the map provided on this website. This map also shows 11 Tree Trimming, 4.8kV Hardening (called "Strengthen Power Lines"), and PTMM 12 (called "Utility Poles Maintenance"). A current example of this map showing only 13 the Rapid Response layer can be seen in Figure 13.

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#### Figure 13

Customer Excellence Map



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#### 3 Part III System Operations Center (SOC) Modernization

#### 4 **Q66.** What is the SOC Modernization project?

A66. The SOC Modernization project is aimed at replacing the Company's previous
outdated primary SOC and the smaller, outdated backup SOC by constructing two
facilities designed using current security, resiliency, and operability standards. The
two new facilities are called the Electric System Operations Center (ESOC) and the
Alternate System Operations Center (ASOC). The previous SOC and backup SOC
have significant limitations, which I will describe later in my testimony. Capital

**MEA-55** 



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investment details of the SOC projects are included in Exhibit A-12, Schedule B5.4,
 page 12. Also included on Exhibit A-12, Schedule B5.4 for the SOC is AFUDC
 on page 13 and plant activity on page 19, described in more detail by Company
 Witness Miller.

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## 6 **Q67.** What functions does the SOC perform?

7 A67. The SOC is the most critical facility in Distribution Operations. Personnel in the 8 SOC operate the subtransmission and distribution system in southeast Michigan, 9 and support generation operations. They monitor alarms and system conditions, 10 and direct field personnel to operate electrical equipment for routine switching 11 needed for maintenance, other planned activities, and for outage restoration. SOC 12 System Supervisors are the ultimate authority for the DTE electrical system 13 operation with the goal of maintaining safety of the field personnel and public, 14 reliability of the electrical grid and the continuity of service to the customers. The 15 SOC also coordinates with Electric Dispatch personnel to ensure appropriate crews 16 are assigned to address system issues.

17

## 18 **Q68.** Why was the SOC Modernization project needed to replace the previous SOC

### 19 facility?

## A68. The previous SOC had several limitations, which DTE Electric identified through extensive benchmarking at the inception of this project:

22

23

24

• Outdated facility: The facility lacks the redundancy in mechanical and electrical systems that is necessary to ensure continued operations in the event of a crisis.

1 Outdated technology: The previous SOC utilizes a magnetic tile board • 2 representation of the electric network, as opposed to an electronic display 3 board of the transmission, subtransmission, and distribution network that is now common in the industry. This severely limits situational awareness, 4 5 which is critical to understanding the current status of the system. The tile 6 map board, located on a vertical wall inside the facility, is also running out 7 of space to accommodate growth and limits training opportunities. 8 Whenever a change occurs on the system, which happens many times per 9 day, an employee must manually mark open and shut circuits by placing a 10 magnetic marker on the wall with a 20+ foot pole.

Space limitations: DTE Electric's SOC and dispatch personnel were
 physically separated, which required repeated phone calls to communicate.
 The co-location of SOC and dispatch personnel is a well-established industry
 best practice and provides customer benefits in terms of improved speed to
 resolve trouble.

Limited visibility of telecommunication infrastructure performance: The reliability of the telecommunication paths from field devices to the SOC is critical for the effective monitoring of the grid and remote operations.
 Developing the ability to separately monitor the condition of the telecommunication network through the construction of a Network Operations Center (NOC) is part of the SOC Modernization project.

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1	Q69.	Has the Commission approved the investment in the new ESOC for inclusion
2		in rate base?
3	A69.	Yes. In Order No. U-20836, the Commission approved capital expenditures for the
4		ESOC in the amount of \$98.5 million, acknowledging NERC certification
5		requirements and other benefits from the modernization of the Company's
6		operational control center.
7		
8	Q70.	What are the investment amounts being requested for ESOC in this instant
9		case?
10	A70.	The Company is requesting approximately \$1.6 million in the bridge period and the
11		projected test year in the ESOC as described in Exhibit A-12, Schedule B5.4, page
12		12. The investment in 2022 and 2023 are primarily to support the development of
13		the IT systems supporting ESOC as a whole, and the new ADMS (as described in
14		Company Witness Smith's testimony). Examples include: Network engineering
15		support during transition into ESOC, setting up ADMS systems, and setting up the
16		main and regional video walls.
17		
18	Q71.	Why are these investments in ESOC necessary and reasonable to serve
19		customers?
20	A71.	The investments for which the Company seeks cost recovery are for projects that
21		have been implemented, or are on track to be implemented prior to the end of the
22		projected test year. These enhancements are necessary to enhance the operational
23		capability of ESOC, which is core to managing the subtransimission and
24		distribution systems, emergent trouble, and storm events. The Company
25		acknowledges the Commission's expectation in Case No. 20836 that, after the

Line <u>No.</u> Line

No. 1 \$98.5 million in approved ESOC investments, there would be no further capital 2 investment in the ESOC during the facilities' planned lifecycle. However, the 3 ESOC is a critical operational resource for the Company and will require 4 incremental investments to maintain and evolve to meet future needs. 5 6 **Q72.** What progress has been made on the construction of the new ESOC? 7 Construction of the new ESOC is complete, all personnel have moved into the new A72. 8 facility for day-to-day operations, and the only work remaining is the finalization 9 of IT infrastructure supporting the new ADMS, which is anticipated to be 10 completed by Q1 2023. The ADMS project is discussed in this instant case in the 11 testimony of Company Witness Smith. 12 13 **O73.** What is the utilization rate of the new ESOC? 14 A73. All SOC and Electric Dispatch employees (including their leadership) are currently 15 working in the ESOC. These employees work rotating shifts to cover operations 16 24 hours per day, 7 days a week, and they do not work remotely. The Operational 17 Engineering (OE) employees who support the SOC and Electric Dispatch 18 employees, are currently working a hybrid schedule in the ESOC. These employees 19 all report to the ESOC in person on Tuesday/Wednesday/Thursday. The OE 20 employees rotate who works remotely, and who works in person in ESOC on 21 Monday/Tuesday. This schedule may change (increased number of staff in person) 22 on any given day, including the weekends, based on workload and operational need. 23 The SCADA Realtime Support (SRS) are all working in ESOC following a hybrid 24 schedule which includes up to 25% of the team on-site at any one time, and the 25 remainder working remotely. All the SRS employees participate in this onLine No.

1

2

3

4

site/remote work rotation. The full team (SOC, Electric Dispatch, OE, SRS) are required to work on-site in the ESOC as the team mission requires (e.g., catastrophic storms and other emergencies). Additional Company personnel with storm duty roles are also required to work on-site during emergencies.

5

### 6 Q74. Has the Company realized the expected benefits by utilizing the new ESOC?

A74. Yes. Per my testimony in Case No. U-20836, the Company expected benefits to
offset the limitations in the previous SOC, including efficiency and collaboration
improvements by the co-location of all pertinent resources, and the use of the new
real-time video wall. Following, are examples of how the Company has realized
these benefits in day-to-day operations since the SOC and Electric Dispatch
employees have been working in the new ESOC, with the new video wall:

13

14 General Cross Functional Teamwork: During the storms in summer of 2022, the 15 ESOC held its first joint huddle (15-minute team check-ins) between the SOC and 16 Electric Dispatch Teams. This collaborative effort permitted the control room 17 teams to align on storm efforts and expectations, such as prioritizing outages, 18 transparent designation of points of contact for dispatching resources, and 19 restoration estimate strategy to name a few. Additionally, SOC personnel have 20 assisted in training Electric Dispatch personnel in our ESOC Training Room in 21 trouble analysis as a Power Dispatcher, and in ADMS to hone their skills and 22 respond in a more efficient manner for emergencies on the electric system.

23

Lombard Significant Event: A loss of major substation equipment occurred at
 Lombard Substation on 10/03/2022 which affected approximately 4,500 customers

#### **MEA-60**

1 in the Warren area. This substation feeds a geographic area that is supported by 2 three different Company service centers (reporting sites for frontline employees, 3 such as Overhead Linemen). In the past, time would be lost coordinating the 4 resources from the three supporting service centers as communications would need 5 to occur between the SOC Operator and multiple Electric Dispatchers over the 6 phone. In this case, the SOC Senior Operator, and Electric Dispatch General 7 Supervisor were able to meet immediately at the center of the control room to 8 review real-time information in the system and on the video wall align on outage 9 indications, hosted a joint call with the service center leadership to designate a 10 responsible service center, and dispatched all necessary resources 10 minutes later. 11 This resulted in the efficient restoration of all customers within 4 hours.

12

Line

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13 Twelve Mile Significant Event: Following a catastrophic fire at Twelve Mile 14 Substation serving the Royal Oak area on 08/08/2022, over 7,600 customers were 15 affected and lost power. The SOC Senior Operator held regular ICS (Incident 16 Command System) meetings, and had impromptu in-person discussions, when 17 necessary, with the Electric Dispatch team to ensure all necessary resources were 18 properly deployed to work around the clock to restore power to our customers. This 19 included escalating resource needs proactively between shifts, and when crews 20 were unavailable to help, to coordinate additional support from adjacent service 21 centers and contractor resources as needed. This led to the efficient restoration of 22 all customers, which required overhead reconfiguration, the deployment of 3 23 portable ISO transformer skids, 3 portable diesel generator locations, and 1 portable 24 substation, within 42 hours of the outage occurring.

25

1 Momentary Breaker Operations (Distribution and Subtransmission): Due to 2 temporary faults on our electric system (i.e., a tree branch momentarily blowing 3 into the Overhead lines), on occasion breakers will open and reclose to restore 4 power to our customers. This creates momentary loss of power to the affected 5 customers, which results in a number of customer calls (flickers, no power, low 6 voltage, etc.) being created. When the Company sends crews to remediate these 7 customer concerns, they often result in an "OK on Arrival" status, meaning there is 8 no continued issue for the field crew to fix, due to no actual persistent issue existing 9 for an individual customer. This pulls field crews away from other productive work 10 on the electric system to mitigate potential safety hazards for the public and 11 sustained outages. However, the ESOC control room regional design creates an 12 environment for those frontline team members who assign resources (Power 13 Dispatchers) to sit side-by-side with the employees that monitor and direct the work 14 on the electric system (System Supervisors/Operators). When a breaker cycles and 15 a momentary fault is observed, the System Supervisor can share that information 16 with the Power Dispatcher to prevent unnecessary truck rolls to customers who do 17 not actually have a persistent issue. Instead, the Company is able to remotely 18 validate customer's power status through AMI indications, and calling the customer 19 directly, to ensure normalcy rather than responding in person.

20

## Q75. With the completion of the new ESOC, is a new backup facility (ASOC) still needed?

A75. Yes. The reasons for building a new modernized backup facility have not changed
since the Commission originally approved building a new ASOC in Case No. U20561. As stated in Witness Bruzzano's testimony in Case No. U-20561 (4T 199),

### **MEA-62**

1 given the critical nature of the ESOC in operating the electric infrastructure, under 2 any emergency conditions, a backup facility is required in the event the primary 3 facility is inoperable. While we do utilize the current backup SOC on occasion, the 4 facility is inadequate for sustained operations, and for disaster recovery efforts. 5 Though it does meet minimum regulatory requirements for NERC regulated 6 Balancing Authority and Generator Operator tasks, managing the distribution 7 system, and recovering from a storm or other disaster from the existing backup SOC 8 would be extraordinarily challenging, and delay restoration of the distribution 9 system.

10

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11 The new backup SOC, also known as the ASOC, will have the appropriate square 12 footage required to co-locate necessary personnel, and will have the appropriate 13 mechanical and electrical system redundancies. In addition, the new ASOC will 14 also be outfitted with the same ADMS technology (including a video wall) as the 15 new ESOC, for seamless operations during the transition between facilities. This 16 will allow the Company to continue the use of the electronic records of the Network 17 Model rather than reverting to a paper version, as is used in the current backup 18 facility. The planned location of the new ASOC will be connected to the new 19 Waterford Service center (as discussed in Company Witness Uzenski's testimony). 20 The ASOC will be located approximately 25 miles away from the new ESOC and 21 will allow the Company to safely operate the grid in the case of a major adverse 22 event at ESOC. Having both a primary and alternate location to operate the grid is 23 a NERC requirement to be able to operate the electrical system and to recover from 24 a catastrophic event safely and quickly.

#### Line <u>No.</u>

# Q76. Why did the Company decide to build the ASOC connected to the new Waterford Service Center?

3 A76. The ASOC was still in its conceptual design phase when Company Witness 4 Bruzzano's testimony in MPSC Case No. U-20561 was submitted. Once the 5 Company obtained a full design with appropriate requirements, the forecasted 6 investments were significantly higher than what was initially presented. As stated 7 in my testimony in MPSC Case No. U-20836, the Company determined that by 8 constructing the ASOC at the same location as the new proposed Waterford service 9 center, the Company will be able to leverage synergies in construction and reduce 10 overall investments closer in alignment to the initial estimates provided in Case No. 11 U-20561. This new location still allows the control room to relocate in case of an 12 emergency in a reasonable amount of time to not affect operations, and the shared 13 space in the new service center will allow for the co-location of the critical support 14 staff as well.

15

## Q77. Did the Commission express any concerns with approving the new ASOC for inclusion in rate base in Case No. U-20836?

A77. Yes, because the new ASOC was considered in its early planning and conceptual
design phase. Pages 137-138 in the 11/18/2022 Order in Case No. U-20836 state
"In this immediate case, DTE Electric acknowledges that the project is still in the
planning and conceptual phase. See, Page 138 U-20836 7 Tr 1529. Therefore, the
Commission finds that it is not reasonable and prudent to approve the capital costs
for the ASOC at this time."

24

25

Line	
No.	

1	Q78.	Is the ASOC project still in the early stages of planning and conceptual design?
2	A78.	No. The ASOC and Waterford service center design is complete, and the facility is
3		currently under construction as site preparation began 11/11/2022, and foundation
4		construction began 12/14/2022. The ASOC project construction is anticipated to be
5		complete in 2024. Waterford service center is supported by Company Witness
6		Uzenski.
7		
8	Q79.	How will customers benefit from the total SOC Modernization project?
9	A79.	As described earlier in my testimony, the SOC Modernization project consists of
10		building two facilities, ESOC and ASOC, to address the limitations in the original
11		facilities. Customers will benefit from the improved communication paths between
12		the resources that will be co-located in the new facilities, which will facilitate
13		quicker and improved coordination to create and implement restoration strategies
14		more effectively. Plus, customers will benefit from reduced risk in disruption in
15		operations during outage events, and faster restoration times regardless of the
16		facility from which the System Operations organization is forced to operate. The
17		ability to understand system conditions, and dispatch resources to address issues,
18		will be greatly enhanced by the technology available in the new facilities and the
19		co-location of the system Operators, Power Dispatchers, and support personnel. In
20		addition, ESOC is more resilient and hardened to withstand adverse natural and
21		man-made disasters, allowing electric grid operations to recover much more
22		quickly in the event of a major catastrophe. These benefits have already started to
23		materialize due to the utilization of the ESOC, as discussed earlier in my testimony,
24		and will be fully realized once the ASOC is complete.
25		

Line <u>No.</u>

## 1 **Q80.** Does this complete your direct testimony?

2 A80. Yes, it does.

## STATE OF MICHIGAN

## BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)
DTE ELECTRIC COMPANY	)
for authority to increase its rates, amend	)
its rate schedules and rules governing the	)
distribution and supply of electric energy, and	)
for miscellaneous accounting authority.	)

Case No. U-21297

## QUALIFICATIONS

## AND

## DIRECT TESTIMONY

## OF

## KEEGAN O. FARRELL

## DTE ELECTRIC COMPANY QUALIFICATIONS AND DIRECT TESTIMONY OF KEEGAN O. FARRELL

Line <u>No.</u>

1	Q1.	What is your name, business address and by whom are you employed?
2	A1.	My name is Keegan O. Farrell (he/him/his). My business address is: One Energy
3		Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company (DTE
4		Electric or Company) as the Manager of Demand Response.
5		
6	Q2.	On whose behalf are you testifying?
7	A2.	I am testifying on behalf of DTE Electric.
8		
9	Q3.	What is your educational background?
10	A3.	I graduated from Michigan State University with a Bachelor of Arts Degree in
11		Communication. In addition, I received a Master of Science Degree in Decision
12		Technologies from the University of North Texas.
13		
14	Q4.	What is your work experience?
15	A4.	From 2008 until 2012, I was employed by DTE Gas Resources, LLC in Fort Worth,
16		Texas where I held positions of increasing responsibility, ultimately serving as a
17		Decision Support Analyst. In this role, I was responsible for assisting with
18		calculating reservoir economics, monitoring daily oil and natural gas production,
19		and overseeing the compliance and emission calculations for the Environmental
20		Protection Agency's Greenhouse Gas Reporting Program (Subpart W). In 2012, I
21		joined DTE Energy as a Senior Business Financial Analyst – Load Research. In
22		2014, I was promoted to Principal Financial Analyst - Load Research. In this
23		position, I was responsible for developing and implementing statistical sampling
24		programs used to evaluate customer class usage characteristics, developing

<u>No.</u>		
1		allocation schedules for use in cost-of-service studies and rate design, and for
2		measuring and evaluating demand response programs offered by the Company.
3		
4	Q5.	Do you hold any certifications or are you a member of any professional
5		organizations?
6	A5.	Yes. I am the course coordinator for the Association of Edison Illuminating
7		Companies (AEIC) Fundamentals for Load Data Analysis course. In addition, I
8		represent DTE Energy on the board of the Peak Load Management Alliance
9		(PLMA).
10		
11	Q6.	Have you received industry related training?
12	A6.	Yes. I have completed the AEIC Fundamentals of Load Data Analysis course. I
13		have also attended various courses at Michigan State University Institute of Public
14		Utilities Annual Regulatory Studies Program as well as the Demand Response
15		Fundamentals and Evolution Course presented by the PLMA.
16		
17	Q7.	What are your current duties and responsibilities?
18	A7.	I am responsible for overseeing DTE Electric's Demand Response (DR) portfolio
19		which includes the short- and long-term strategic, marketing and implementation
20		of DR programs. I am also responsible for the development and implementation of
21		gas DR.
22		
23	Q8.	Have you previously sponsored testimony before the Michigan Public Service
24		Commission (MPSC or Commission)?

## 1 A8. Yes. I have sponsored testimony and exhibits before the MPSC in the following

2	DTE Electri	DTE Electric cases:		
3	Case No.	Description		
4	U-18014	DTE Electric 2016 General Rate Case		
5	U-18255	DTE Electric 2017 General Rate Case		
6	U-20162	DTE Electric 2018 General Rate Case		
7	U-20471	DTE Electric 2019 Integrated Resource Plan (IRP)		
8	U-20521	DTE Electric 2017-2018 Demand Response Reconciliation Case		
9	U-20793	DTE Electric 2019 Demand Response Reconciliation Case		
10	U-21044	DTE Electric 2020 Demand Response Reconciliation Case		
11	U-20836	2022 DTE Electric General Rate Case		
12	U-21242	DTE Electric 2021 Demand Response Reconciliation		
13	U-21193	DTE Electric 2022 IRP		

101				
1	Purpose of Testimony			
2	Q9.	What is t	the purpose of	of your testimony?
3	A9.	The purp	ose of my dire	ect testimony is to discuss the development of DR efforts that
4		DTE Elec	etric is condu	cting and provide support for the expenditures and activities
5		associate	d with the	continuation of existing programs and pilots, and the
6		Company	's proposals	for new pilots.
7				
8	Q10.	Are you	sponsoring a	ny exhibits in this proceeding?
9	A10.	Yes. I am	n sponsoring i	n whole, or in part, the following exhibits:
10		<u>Exhibit</u>	Schedule	Description
11		A-12	B5.6	Capital Expenditures – Demand Response Portfolio and
12				DTE Insight (page 1, lines 1-4 and page 2, lines 1-15)
13		A-12	B5.6.1	Battery Storage Pilot Document
14		A-12	B5.6.2	Residential Generator Pilot Document
15		A-13	C5.9	Demonstrating and Selling Expenses-DR (line 9)
16				
17	Q11.	Were these exhibits prepared by you or under your direction?		
18	A11.	Yes, they	were.	
19				
20	Q12.	How is y	our testimon	y organized?
21	A12.	My testin	nony consists	of the following five parts:

<u>No.</u>

22

23

24

25

Part I

Part II

Part III

Part IV

Line

### KOF-4

Programmable Controllable Thermostat (PCT) Program

Interruptible Space Conditioning Program

Demand Response Portfolio

**Regulatory Framework** 

Line			<b>K. O. FARRELL</b> U-21297
<u>No.</u>			
1		Part V	Bring-Your-Own-Device (BYOD) Program
2		Part VI	Other Demand Response Program Enhancements and Pilots
3			
4	<u>Part I</u>	: Demand Re	sponse Portfolio
5	Q13.	What is the o	overall purpose of the DR programs and pilots that the Company
6		is managing	and investing in?
7	A13.	The Company	has been managing and investing in a diverse range of programs and
8		pilots that se	rve as resources in the Company's integrated resource planning.
9		Significant ch	hanges have been occurring in the energy landscape in the State of
10		Michigan incl	luding energy legislation, regulatory framework, and environmental
11		regulations. T	hese changes, coupled with a shift from fossil fuel-based generation
12		to renewable	generation, are driving investment in a DR portfolio to support
13		resource adeq	uacy. DR programs are, and will continue to be, an important part of
14		DTE Electric	's integrated resource portfolio. The Company's DR programs are
15		being designe	d and managed to help reduce enrolled customers' energy use during
16		peak hours. T	he reduction in customer usage from DR programs provides value to
17		both the utilit	y and the customer through reduced capacity costs, and in turn, can
18		provide lower	bills or incentives for customers utilizing the programs.
19			
20		The DR progr	ams are part of a utility system framework within the comprehensive
21		context of an	Integrated Resource Plan (IRP) process. DTE Electric develops,

validates, and manages these programs, which offer customers a range of options
consisting of products, customer incentives, tariff structures, and education based
on their profiles and customers' willingness to curtail energy usage during peak
hours. As part of the development process, the internal DR organization evaluates

programs and pilots, customer behavior, program acceptance and validates technologies that can deliver benefits to utility customers. A portfolio of functioning programs enabled the Company to continue providing secure, reliable, and sustainable energy supply to its customers under a changing generation capacity and energy landscape and will continue to do so in the coming years.

6

### 7 Q14. Could you describe the Company's current DR portfolio?

A14. Yes. The goal of the Company's DR programs is to deliver measurable peak
demand reduction by effectively engaging customers to manage and reduce or shift
their energy consumption. The Company currently receives capacity credit from
the Midcontinent Independent System Operator (MISO) from its established DR
portfolio, which is a diverse set of programs for residential, commercial, and
industrial customers. In addition, the Company continues to invest in various pilots
to enhance the current portfolio offerings, as well as leverage new technologies.

15

Pilots are potential programs focused on understanding technology or design and determining whether they can become full-scale programs that will deliver accountable peak demand reduction or shifts in energy consumption. Pilots can eventually become programs in the Company's DR portfolio if they prove to be successful and provide customer value.

21

In 2021, the U.S. Energy Information Administration (EIA) ranked DTE's DR portfolio the sixth largest in the Country in terms of Potential Peak Demand Savings. This also ranked the Company's portfolio as the largest in the MISO in terms of Potential Peak Demand Savings.

		K. O. FARRELL
Line <u>No.</u>		U-21297
1		
2	Q15.	How much capacity does the Company's existing DR portfolio account for in
3		meeting MISO's resource adequacy requirements?
4	A15.	For the 2022/2023 MISO Plan Year, DTE Electric's portfolio had 786 MWs
5		(installed capacity or ICAP) of demand response which equated to 877 MWs of
6		MISO Load Modifying Resources (LMRs) used to meet resource adequacy
7		requirements. ICAP MWs by program are broken out by program in Table 1.
8		

- 9

Program	MWs
R10 Interruptible Primary Supply	320
D1.1 Interruptible Space Conditioning	174
D8 Interruptible Primary Service	104
R1.2 Electric Process Heating	64
Smart Savers (BYOD)	59
R12 Capacity Release	32
SmartCurrents & D1.8 Dynamic Peak Pricing	16
D3.3 Interruptible General Service	13
R1.1 Metal Melting	4
Total	786

Table 1DTE Electric 2022/23 DR Portfolio

10

## 11 Part II: Regulatory Framework

12 **Q16.** Is the evaluation and cost recovery of Demand Response investments governed

13 by a specific regulatory framework?

110

A16. Yes. The investments in DR are evaluated under the three-phase framework approved by the Commission in Case U-18369 on September 15, 2017.

3

2

1

4 Q17. Could you describe the regulatory framework adopted by the Commission to 5 approve, recover, and reconcile expenditures in the Company's DR portfolio? 6 A17. Yes. The Commission adopted the Staff's recommendation of a "three-phase" 7 approach with some modifications. The three-phase approach is a multi-step 8 process which evaluates DR proposals in the context of the IRP in the first phase. 9 After DR plans are approved as part of the IRP, the DR program capital costs are 10 considered approved and are included in rates in the utility's next general rate case 11 during the second phase. The utility can propose changes to its DR programs or 12 pilots that can be evaluated and approved in general rate cases or demand response 13 reconciliation filings and later included in the following IRP. The third phase 14 involves a reconciliation of the DR costs, participation rates, and demand savings 15 achieved on an annual basis. The Commission also stated that during the 16 reconciliation proceedings actual capital spending in the examination period will 17 be reconciled against the amount approved in the IRP and recovered in the rate case 18 while Operation and Maintenance ("O&M") spending will be reconciled against 19 the amount approved and recovered in the general rate case.

20

### 21 Q18. How much did the Company invest in the DR portfolio in 2022?

A18. The Company spent \$9.3 million in capital expenditures associated with the DR
portfolio in 2022. O&M expenditures associated with the DR portfolio were \$2.6
million in 2022. These expenditures will be subject to the 2022 DR reconciliation
that will be filed no later than July 1, 2023.

<u>No.</u>		
1		
2	Q19.	What programs are the Company actively investing in to grow the DR
3		portfolio?
4	A19.	In order to grow the DR portfolio in terms of MWs, the Company is investing
5		capital and O&M dollars into the CoolCurrents <sup>TM</sup> , the SmartCurrents <sup>TM</sup> program
6		and the Smart Savers program as well as new pilots. The majority of the MWs in
7		the DR portfolio is made up of legacy tariffs (D3.3, D8, R1.1, R1.2 and R10) that
8		currently have no investment associated with them.
9		
10	Q20.	How much is the Company forecasting to invest in the DR portfolio during the
11		bridge period of January 1, 2022 through November 30, 2023, and the
12		projected test year December 1, 2023 through November 30, 2024?
13	A20.	The Company is forecasting to invest capital expenditures in the DR portfolio in
14		the amount of \$18.6 million for the bridge period of January 1, 2022 through
15		November 30, 2023, and \$5.6 million for the projected test year beginning on
16		December 1, 2023 and ending on November 30, 2024. A breakdown of these capital
17		expenditures is shown in Exhibit A-12, Schedule B5.6, Page 1 of 2. In addition,
18		the Company is forecasting to spend \$5.9 million annually beginning in 2023 in
19		operation and maintenance (O&M) expenses in support of the DR programs and
20		pilots. The associated O&M expenses are shown in Company Witness Peterson's
21		Exhibit A-13 Schedule C5.9, line 9.
22		
23	Q21.	Why is the Company forecasting to reduce the capital expenditures associated
24		with DR from the bridge period to the forecasted test year?

Line <u>No.</u>		U-21297
1	A21.	The reduction in capital comes from the Company finishing the CoolCurrents
2		replacement project as well utilizing customer owned equipment (such as
3		thermostats) rather than Company owned hardware to respond to DR events.
4		
5	Q22.	How do the O&M expenses support DR programs?
6	A22.	The estimated expenses of \$5.9 million represent the funding needed to support the
7		marketing, operation, and development of the portfolio of programs and pilots
8		including staffing requirements to manage and monitor the existing portfolio,
9		software, and technology to effectively run the programs and targeted customer
10		incentives.
11		
12	Q23.	Why is the Company planning to increase the annual projected O&M
13		expenses versus the expenditure levels from prior annual periods?
14	A23.	Consistent with my testimony in Case U-20836, DR programs continue to become
15		more O&M based as the Company continues to focus its material and human
16		resources on the operation and maintenance of such programs. Given the nature of
17		these activities, the associated expenditures are considered O&M expenses from an
18		accounting perspective. In addition, external platform solutions that utilize cloud
19		technology are categorized as software-as-a-service procurement and are
20		considered an O&M expense. The Company expects that this kind of technology
21		solution and type of service supply will become more prevalent for programs and
22		pilots in the future.
23		
24	Q24.	Is the DTE Insight Program and associated investment a component of the
25		Company's DR portfolio?

## KOF-10

1	A24.	No. DTE Insight is a stand-alone program developed around a mobile application
2		that aims to drive customer behavior with the goal of reducing both overall energy
3		(gas and electricity) consumption and electricity demand during peak hours. The
4		DTE Insight program is discussed in the testimony of Company Witness Nguyen.
5		
6	<u>Part l</u>	II: Interruptible Space Conditioning Program
7	Q25.	What is the Interruptible Space Conditioning program?
8	A25.	The interruptible space conditioning program, commonly referred to
9		CoolCurrents <sup>TM</sup> is a dispatchable DR program in which a direct load control device
10		(LCD) is installed on a customer's air conditioning unit or central heat pump in
11		exchange for a discounted energy charge on the associated usage. The Company is
12		offering the CoolCurrents <sup>TM</sup> program under the Tariff D1.1 Interruptible Space
13		Conditioning Service Rate. As of December 31, 2022 nearly 260,860 residential
14		customers and 838 commercial customers take service on the rate.
15		
16	Q26.	What is the status of the Company's CoolCurrents <sup>TM</sup> LCD replacement
17		program?
18	A26.	Since the Company started replacing legacy LCDs in 2015, the Company has
19		successfully replaced a cumulative total of 170,047 units as of December 31, 2022.
20		Approximately 90,000 customers still have legacy Radio Control Units (RCUs).
21		These are largely sites that no longer have proper wiring or will require return visits
22		due to access issues.
23		
24	Q27.	Why is the Company continuing to make these improvements?

Line	
No	

1	A27.	The Company identified that replacing the outdated infrastructure results in a higher
2		capacity value through increased capabilities and effectiveness. As the new LCDs
3		are two way communicating devices, they allow DTE to determine whether devices
4		are available for interruption. They also provide flexibility to interrupt at substation
5		or circuit level. Since the project began The Company has increased the MWs
6		associated with the CoolCurrents program through the replacement of units by 76
7		MWs. With continuous investment in the CoolCurrents <sup>TM</sup> program, DTE is able to
8		extend the equipment life as well as increase the available capacity in MISO and
9		continue to provide an additional demand response program option for residential
10		and commercial customers.
11		
12	Q28.	Has the Company found any technical issues during the recent replacement
13		activities?
14	A28.	Yes. The Company found that some of the legacy LCD switches or Radio Control
15		Units (RCUs) are no longer connected by the necessary 24v wiring which powers
16		the switch. Without this wiring, a new LCD switch will not operate. In order for the
17		equipment to become operational, a customer will have to have an electrician repair
18		the wiring to accommodate the control unit.
19		
20	Q29.	Is the Company addressing the technical installation issue in some of the
21		customers' legacy switches?
22	A29.	Yes. DTE Electric is evaluating the effectiveness of a pro-active campaign to
23		request customers who do not have the proper wiring to contact an electrician to
24		repair the 24v line. This campaign began in 2022. As of December 31, 2022, 7,845

## KOF-12

No.1Service to request to have a contractor fix their wiring with 422 customers taking2the appropriate action. The Company continues to evaluate the success rate of this3campaign.

4

Line

5 In addition, the Company has identified a solution that would not require a 24v line 6 and involves reconfiguring the current LCDs. The Company plans to reconfigure 7 5,000 of the current LCDs and install them in 2023 as a trial. If deemed successful, 8 then the Company plans to move forward with this approach.

9

Q30. What are the Company's planned efforts in managing the CoolCurrents<sup>™</sup>
program?

12 A30. Moving forward, the Company plans to promote the CoolCurrents<sup>TM</sup> program to 13 new customers who heat and cool their home with a whole-home air source heat 14 pump. DTE Electric intends to work with a third party to identify customers with a 15 whole-home air source heat pump through load analysis. D1.1 electric load in the 16 winter months from air source heat pumps could provide the opportunity for the 17 CoolCurrents<sup>TM</sup> program to act as a year-round LMR for the Company. 18 Additionally, air source heat pump customers can receive savings on their 19 equipment usage year-round through a discounted rate. The Company also plans to actively market to current CoolCurrents<sup>™</sup> customers who no longer want to be 20 21 on the discounted rate, an alternative such as Smart Savers or SmartCurrents<sup>™</sup>, in 22 an effort to retain them as a demand response customer.

23

1 Q31. How much is the Company forecasting to invest in the CoolCurrents<sup>TM</sup> 2 program during the bridge period of January 1, 2022 through November 30, 3 2023, and in the projected test year ending November 30, 2024? 4 The Company is forecasting to invest \$4.2 million in capital expenditures in the A31. 5 projected bridge period January 1, 2022 through November 30, 2023, and \$0.6 6 million in the projected test year extending from December 1, 2023 to November 7 30, 2024. Overall, the investment plan supports the continuation and final year of 8 mass replacements of the existing CoolCurrents<sup>TM</sup> replacement program as 9 approved by the Commission in its Orders for general rate Case Nos. U-17767, U-10 18014, U-18255, U-20162, U-20561, and U-20836 and for the Company's IRP 11 Case No. U-20471. It also supports the focused expansion of the CoolCurrents<sup>TM</sup> 12 Program to whole-home air source heat pump customers. The associated projected 13 capital expenditures are shown in Exhibit A-12, Schedule B5.6, page 1 of 2, line 5, 14 columns (c) through (f). 15 16 Part IV: Programmable Controllable Thermostat (PCT) Program 17 Q32. **Could you please describe the PCT Program?** 18 A32. The PCT program, marketed under the name SmartCurrents<sup>TM</sup>, is a program where 19 the Company provides a wi-fi enabled PCT thermostat to a customer. In exchange 20 for the thermostat, the Company is able to adjust the setpoint on the thermostat 21 during DR events. 22 23 Q33. How many customers are enrolled in SmartCurrents<sup>TM</sup>?

No. 1 A33. As of December 31, 2022, the Company has enrolled 21,134 customers in the PCT 2 program. The Company is currently claiming 16 MWs of available capacity in the 3 2022/23 MISO PRA. 4 5 The Company expects a continued growth in customer enrollment levels, by 6 modifying the PCT program based on previous customer research and feedback of 7 barriers to enrollment and continued participation, throughout the bridge period 8 from January 2022 through November 2023 and the projected test year from 9 December 2023 through November 2024. The implementation of the PCT program 10 includes the continued recruiting of new customers for continued expansion of the 11 program. 12 13 034. Is the Company making any changes to the program? 14 A34. Yes. Beginning in 2023, the SmartCurrents<sup>™</sup> program will be separated from the 15 Dynamic Peak Pricing (DPP) rate, or D1.8, meaning that customers will be able to 16 take service under any Residential Electric base rate, including DPP, to participate 17 in the SmartCurrents<sup>TM</sup> program. 18 19 035. Why did the Company think it was necessary to separate the SmartCurrents<sup>TM</sup> 20 **Program from the DPP rate?** 21 A35. The Company felt it was necessary to make this change to ensure the 22 SmartCurrents<sup>™</sup> program can continue to provide value to the customer and the 23 Company. Separating SmartCurrents<sup>TM</sup> program from the D1.8 tariff provides 24 greater flexibility within the program allowing the Company to make necessary 25 changes to continue to comply with any MISO DR accreditation requirement

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changes while also providing the customers with more option to select the rate that best fits their household and lifestyle. Removing the tariff requirement also opens up eligibility to customers who previously may have been denied enrollment due to tariff incompatibilities.

6 In addition, the DPP rate structure is a barrier for customers to enroll on the SmartCurrents<sup>™</sup> program. Customers perceive the rate to be difficult to understand 7 8 with minimal benefit to outweigh the potential impact of Critical Peak Pricing. 9 Participants were recently surveyed in an ad hoc quantitative study to understand 10 how they would rate select attributes of the SmartCurrents<sup>TM</sup> program including: 11 ease of enrollment; ease of using the app associated with the smart thermostat; ease 12 of program participation; interaction(s) with customer service regarding the 13 program; clear, easy-to-understand communications explaining the program; ease 14 of installation of the smart thermostat; amount of program information/resources 15 available to participants; ease of understanding the DPP rate; and amount of money 16 saved by participating in the program so far. Of those attributes, the ease of 17 understanding the DPP rate and amount of money saved by participating in the 18 program so far were rated the lowest.

19

### 20 Q36. Is the Company making any other changes to the program?

- A36. Yes. The Company plans to make several changes to the program in addition to
   removing the DPP rate requirement, including:
- Upgrading the thermostat model offered to one more current and
   identifying an additional one-time incentive for current participants who
   enrolled in the program under its original design;

#### KOF-16

10.		
1		• Revising the program's event parameters (e.g., number of events, event
2		hours, notification window, notification channels, etc.) to increase
3		flexibility and availability of SmartCurrents <sup>™</sup> as a LMR resource,
4		• Expanding eligibility criteria to any Residential Electric base rate including
5		DPP, most supplemental base rates except for CoolCurrents, and payment
6		plans including but not limited to BudgetWise Billing, and
7		• Providing an annual participation incentive to increase retention.
8		
9	Q37.	What are the planned efforts to manage the SmartCurrents <sup>TM</sup> program going
10		forward?
11	A37.	The Company paused active recruitment of the program on November 1, 2022, in
12		order to redesign the program. Recruitment is tentatively scheduled to restart in
13		April 2023. Program changes will also go into effect on that date and current
14		customers will be educated on the changes. The Company is committed to growing
15		the SmartCurrents <sup>™</sup> program and believes the changes to the program will further
16		the cost effectiveness of the program through increased enrollments and improved
17		event parameters. The Company has benchmarked other utilities who offer both a
18		direct-install program, like SmartCurrents <sup>™</sup> , as well as a BYOD program like
19		Smart Savers and believes both types of programs add value to the DR portfolio.
20		
21	Q38.	How much is the Company forecasting to invest in the PCT program going
22		forward during the bridge period of January 1, 2022 through November 30,
23		2023, and in the projected test year ending on November 30, 2024?
24	A38.	The Company is forecasting to invest \$7.4 million in capital expenditures during
25		the bridge period of January 1, 2022 through November 30, 2023, and \$2.5 million

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1 in capital expenditures during the projected test-year period of December 1, 2023 2 through November 30, 2024. This level of spend is necessary to continue to increase 3 customer enrollment throughout the bridge period and forecasted test year as well 4 as allow the Company to make the previously discussed changes to the program, 5 including digital and IT design and development to implement the program design 6 changes on the frontend (i.e., web) and backend (i.e., CRM system), acquire the 7 inventory of a newer thermostat model, and incentivize participants. Costs are 8 expected to decrease in the test year as the Company works with the program 9 implementer to streamline processes, including increased self- or virtual 10 installation, revised thermostat return materials, and potentially charging for non-11 installed devices, which would result in cost savings. The associated projected 12 capital expenditures are shown in Exhibit A-12, Schedule B5.6, page 1 of 2, line 2, 13 columns (c) through (f). The associated projected O&M expenses are shown in 14 Company Witness Peterson's Exhibit A-13 Schedule C-5.9, line 9.

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#### 16 Part V: Bring-Your-Own-Device (BYOD) Program

#### 17 Q39. What is the Smart Savers program?

18 A39. The Smart Savers program, which is a Bring-Your-Own-Device (BYOD) 19 thermostat program, is available to residential and commercial customers who 20 already have an installed Wi-Fi enabled smart thermostat. The Company 21 incentivizes customers to enroll in the program. Once enrolled, customers' 22 thermostats are configured to allow the Company to send a control signal during 23 demand response events, which raises the thermostat's set-point by up to four 24 degrees during the event. Events only occur Monday through Friday between the hours of 12:00 PM and 8:00 PM and are limited to a cumulative total of 56 hours 25

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1		between the months of June through September. As a result of this change in
2		thermostat configuration at the customer sites, the Company is able to account for
3		demand reduction at peak times during the called event. Smart Savers customers
4		are always notified prior to an event. In some instances, the Company will pre-cool
5		a participant's home to increase the energy savings recognized during the event.
6		The customers can override the event or opt-out completely if they choose to do so.
7		No financial penalties or incentive reductions are associated with the customers'
8		override actions.
9		
10	Q40.	How many devices are enrolled in the Smart Savers Program?
11	A40.	There were 51,160 devices enrolled in the Smart Savers Program as of December
12		31, 2022. The Company is currently claiming 59 MWs of available capacity for the
13		program in the 2022/23 MISO Planning Year as shown previously in Table 1.
14		
15	Q41.	What are the Company's planned efforts for the Smart Savers program going
16		forward?
17	A41.	Based on the previously mentioned results regarding customer engagement through
18		enrollment and event participation, as well as peak demand reduction levels, the
19		Company plans to continue marketing and operating the program. The Company
20		continues to monitor customer behavior during the events and evaluate if additional
21		measures or incentives are necessary to continue customer engagement. Starting in
22		2023, the Company plans to increase the annual incentive from a \$20 gift card to a
23		\$50 bill credit. The Company began registering the BYOD program as an LMR to
24		meet MISO resource adequacy requirements in 2020/2021 and continues to do so
25		annually. The Company plans to invest in the ongoing enrollment and integration

Line <u>No.</u>		<b>K. O. FARRELL</b> U-21297
1		of the new enrollees with an interim goal of 60,000 devices enrolled by the end of
2		2023 and 70,000 devices enrolled by the end of 2024.
3		
4	Q42.	How much is the Company forecasting to invest in the Smart Savers program
5		going forward?
6	A42.	The Company is forecasting to increase the annual O&M spend by \$2.0 million for
7		a total spend of \$3.0 million to support the Smart Savers Program. The increased
8		O&M spend will cover the annual portal fee, the device fees for new enrollees and
9		the annual device renewal fee for current enrolled customers. This level of O&M
10		spend is necessary to reach the estimated enrollment level of 60,000 by the end of
11		2023 and 70,000 by the end of 2024. The associated projected O&M expenses are
12		shown in Company Witness Peterson's Exhibit A-13 Schedule C5.9, as a portion
13		of line 9.
14		
15	<u>Part V</u>	VI: Other Demand Response Program Improvements and Pilots
16	Q43.	What investments is the Company making in DR pilots and other program
17		improvements?
18	A43.	The Company continues to develop new and update existing DR pilots as part of
19		the ongoing evaluation of its DR portfolio. First, the Company is currently
20		implementing the Plug-in Electric Vehicle (PEV or EV) DR pilot. This pilot is
21		known as the DTE Smart Charge pilot. Second, the Company is launching,
21 22		known as the DTE Smart Charge pilot. Second, the Company is launching, marketing, and implementing the Peak Time Savings (PTS) pilot for residential
21 22 23		known as the DTE Smart Charge pilot. Second, the Company is launching, marketing, and implementing the Peak Time Savings (PTS) pilot for residential customers. Third, the Company is working on the implementation plans of a battery
21 22 23 24		known as the DTE Smart Charge pilot. Second, the Company is launching, marketing, and implementing the Peak Time Savings (PTS) pilot for residential customers. Third, the Company is working on the implementation plans of a battery energy storage pilot for or in conjunction with Commercial and Industrial

1		residential generator pilot. Last, the Company's DR organization is supporting the
2		development of Non-Wire Alternatives (NWA) pilots that are being developed
3		under the leadership of the Distribution Operations (DO) organization and
4		sponsored in this instant case by Company's Witness Hill.
5		
6		In addition to the pilots, the Company is in the early stages of improving two
7		programs. The first is the replacement of LCDs in the interruptible water heating
8		program. The second is an enhancement for current C&I interruptible customers
9		and consists of a dashboard or platform that would be provided to C&I customers
10		already on an interruptible rate to help improve event performance.
11		
12	Q44.	Is continuing to invest in DR pilot programs beneficial?
13	A44.	Yes. DR pilots provide the Company with valuable information about how to
13 14	A44.	Yes. DR pilots provide the Company with valuable information about how to integrate the various programs with the Company's equipment, systems, and
13 14 15	A44.	Yes. DR pilots provide the Company with valuable information about how to integrate the various programs with the Company's equipment, systems, and processes as we assess the customer's appetite for such programs. If a pilot program
13 14 15 16	A44.	Yes. DR pilots provide the Company with valuable information about how to integrate the various programs with the Company's equipment, systems, and processes as we assess the customer's appetite for such programs. If a pilot program is selected to be commercialized, then the Company puts together the necessary
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> </ol>	A44.	Yes. DR pilots provide the Company with valuable information about how to integrate the various programs with the Company's equipment, systems, and processes as we assess the customer's appetite for such programs. If a pilot program is selected to be commercialized, then the Company puts together the necessary planning, marketing, and implementation processes to have a successful launch of
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> </ol>	A44.	Yes. DR pilots provide the Company with valuable information about how to integrate the various programs with the Company's equipment, systems, and processes as we assess the customer's appetite for such programs. If a pilot program is selected to be commercialized, then the Company puts together the necessary planning, marketing, and implementation processes to have a successful launch of the program. This approach helps the Company to reduce the ensuing ramp-up time
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> </ol>	A44.	Yes. DR pilots provide the Company with valuable information about how to integrate the various programs with the Company's equipment, systems, and processes as we assess the customer's appetite for such programs. If a pilot program is selected to be commercialized, then the Company puts together the necessary planning, marketing, and implementation processes to have a successful launch of the program. This approach helps the Company to reduce the ensuing ramp-up time necessary to quickly and cost-effectively run those programs when capacity and
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> </ol>	A44.	Yes. DR pilots provide the Company with valuable information about how to integrate the various programs with the Company's equipment, systems, and processes as we assess the customer's appetite for such programs. If a pilot program is selected to be commercialized, then the Company puts together the necessary planning, marketing, and implementation processes to have a successful launch of the program. This approach helps the Company to reduce the ensuing ramp-up time necessary to quickly and cost-effectively run those programs when capacity and reliability needs emerge, as well as evolve with the latest technology.
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> </ol>	A44.	Yes. DR pilots provide the Company with valuable information about how to integrate the various programs with the Company's equipment, systems, and processes as we assess the customer's appetite for such programs. If a pilot program is selected to be commercialized, then the Company puts together the necessary planning, marketing, and implementation processes to have a successful launch of the program. This approach helps the Company to reduce the ensuing ramp-up time necessary to quickly and cost-effectively run those programs when capacity and reliability needs emerge, as well as evolve with the latest technology.
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> </ol>	A44.	Yes. DR pilots provide the Company with valuable information about how to integrate the various programs with the Company's equipment, systems, and processes as we assess the customer's appetite for such programs. If a pilot program is selected to be commercialized, then the Company puts together the necessary planning, marketing, and implementation processes to have a successful launch of the program. This approach helps the Company to reduce the ensuing ramp-up time necessary to quickly and cost-effectively run those programs when capacity and reliability needs emerge, as well as evolve with the latest technology.
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>23</li> </ol>	A44.	Yes. DR pilots provide the Company with valuable information about how to integrate the various programs with the Company's equipment, systems, and processes as we assess the customer's appetite for such programs. If a pilot program is selected to be commercialized, then the Company puts together the necessary planning, marketing, and implementation processes to have a successful launch of the program. This approach helps the Company to reduce the ensuing ramp-up time necessary to quickly and cost-effectively run those programs when capacity and reliability needs emerge, as well as evolve with the latest technology. In addition, conducting pilots help the Company understand event performance and sustainability of the resource. Pilots allow the Company to test different event
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>23</li> <li>24</li> </ol>	A44.	Yes. DR pilots provide the Company with valuable information about how to integrate the various programs with the Company's equipment, systems, and processes as we assess the customer's appetite for such programs. If a pilot program is selected to be commercialized, then the Company puts together the necessary planning, marketing, and implementation processes to have a successful launch of the program. This approach helps the Company to reduce the ensuing ramp-up time necessary to quickly and cost-effectively run those programs when capacity and reliability needs emerge, as well as evolve with the latest technology. In addition, conducting pilots help the Company understand event performance and sustainability of the resource. Pilots allow the Company to test different event parameters (i.e., length of events, notification window, etc.) to assess which

## KOF-21

Q45. How much capital is the Company forecasting in program improvements and
pilot development during the bridge period of January 1, 2022 through
November 30, 2023, and in the projected test year ending on November 30,
2024?

A45. The Company is forecasting to invest \$7.1 million in capital expenditures during
the bridge period of January 1, 2022 through November 30, 2023, and \$2.4 million
in capital expenditures during the projected test year period of December 1, 2023
through November 30, 2024. This level of spend is necessary to support continued
program improvement and pilot development.

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#### 14 <u>Smart Charge Pilot</u>

## 15 **Q46.** What is the Smart Charge pilot?

16 A46. Smart Charge is a current pilot that is designed to assess the effectiveness of the Open Vehicle Grid Integrated Platform (OVGIP) concept to integrate EV charging 17 18 with grid objectives through demand response. The Company continues to conduct 19 the pilot which involves a partnership with select automotive manufacturers 20 (OEMs). The Company is partnering with specific EV automotive manufacturers 21 in its service territory. The Company and the OEMs seek a better understanding of 22 the responsiveness of the EV owners and their willingness to participate in DR 23 events specifically targeted at vehicle charging and the amount of demand that is 24 curtailed through events. Beginning in 2023, the Company will begin to study 25 managed charging, in parallel with the current DR pilot initiatives of DTE Smart

Line <u>No.</u>		U-21297
1		Charge, with the addition of another OEM. The Company will also evaluate
2		Vehicle to Grid (V2G) and Vehicle to Home (V2H) opportunities in collaboration
3		with the OEMs.
4		
5	Q47.	What are the Smart Charge pilot's main objectives?
6	A47.	The Company is focusing on the main pilot objectives as the pilot expands to a
7		larger population:
8		• Evaluate energy reduction (kWh) and demand reduction (kW),
9		• Evaluate results from different times, lengths, and participation levels of
10		events,
11		• Assess EV user behavior in response to different incentive mechanisms
12		such as up front and program-end incentives,
13		• Assess override (Opt-in / Opt-out) approach by EV users, and
14		• Test deliverability of events, for instance, ensuring communication signals
15		functioned properly.
16		
17	Q48.	What are the customer benefits of participating in the Smart Charge pilot?
18	A48.	In addition to receiving a financial incentive from the Company for their
19		participation, pilot customers are able to share feedback to the Company and OEMs
20		on charging habits and shape the future of EV charging as a DR resource.
21		
22	Q49.	What is the estimated impact of the Smart Charge pilot for the pilot duration?
23	A49.	In 2019, the Company called twelve (12) events in a 6-month timeframe. The
24		Company and OEMs identified a total demand response reduction of 702.1 kWh
25		across all 12 events. The average participation from PEVs across all of the events

1 was 24% full participation and 76% partial or non-participation, which overall 2 provided an initial assessment of the customer override behavior (Opt-in/Opt-out). 3 These events consisted of 165 customers who were employees of the OEMs and 4 were designed to ensure any issues (i.e., communication or signal issues) could be 5 solved prior to an expansion of a larger pool of customers. 6 7 In 2021, the Company called 31 events in an 8-month timeframe. The Company 8 and OEMs identified a total demand response reduction of nearly 1.7 MWh across 9 all 31 events. The average participation rate across all events was 30% full 10 participation and 70% partial or non-participation. As more eligible EVs rolled out 11 through 2021, the number of participants within the Smart Charge pilot increased 12 to up to 370 EVs. The Company and OEMs called events during different times of 13 the day with a 2-hour event duration for each called event. 14 15 For the 2022-23 pilot year, the Company planned to call 50 events in a 12-month 16 timeframe. During the first 20 called events, the Company and OEMs identified a 17 total demand response reduction of 2.8 MWh within the first 5 months. The 18 Company plans to call 30 additional events through the pilot's duration, ending 19 May 2023. The Company and OEM are continuing the evaluation of events called 20 during different times of the weekday with a 2-hour event duration. The events 21 with the most avoided energy (kWh) and participation occur overnight, during the 22 12am-2am timeframe. The Company and OEMs are still analyzing participation 23 results from the events called in 2022. As of 12/31/2022, there are 610 EVs

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enrolled.

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1	Q50.	How much is the Company forecasting to invest in the Smart Charge pilot
2		going forward?
3	A50.	The Company is forecasting to spend \$0.7 in O&M annually in support of the Smart
4		Charge pilot. Much of this cost covers the up-front and year-end incentives. Other
5		costs include the OVGIP portal fee and the monthly enrollment fee for each
6		participating EV.
7		
8	Q51.	Has the Commission previously supported the Smart Charge Pilot?
9	A51.	Yes. The Commission supported the pilot in the 2019 IRP (U-20471) and the 2022
10		Electric Rate Case (U-20836). In addition, the Smart Charge Pilot was supported
11		by Staff through settlements in the DR Reconciliation cases (U-20521, U-20793,
12		U-21044 and U-21242).
13		
14	Peak 7	<u>Fime Savings Pilot</u>
15	Q52.	What is the Company's Peak Time Savings (PTS) pilot?
16	A52.	The PTS pilot is structured to reward customers for reducing energy consumption
17		during the Company's called Peak Time Events. The participating customers
18		receive bill credits for each event based on measured reductions in customers'
19		energy demand relative to a pre-established baseline, which was initially developed
20		based on features of comparable utility programs. Unlike the Company's current
21		DPP rate, the PTS pilot does not increase a customer's electric rate during peak
22		events, but instead provides customers with a no-risk introduction to demand
23		response.
24		

25 Q53. What are the main objectives of the proposed PTS pilot?

<u>No.</u>		
1	A53.	The main objectives of the PTS pilot are as follows:
2		• Analyze outcomes to determine potential peak-savings impacts and the
3		impact on rates and revenues;
4		• Assess customer receptiveness and the value customers receive from PTS;
5		and
6		• Identify and process new learnings that could be applied to current and
7		future demand response offerings.
8		
9	Q54.	What are the customer benefits of participating in the PTS pilot?
10	A54.	The PTS pilot provides customers with a tool to become familiarized with the
11		concepts of peak demand and demand response in a "no penalty" environment.
12		Through the PTS pilot, customers will be able to gain a greater understanding of
13		energy usage and its impact on their electric bills and how to save. Because of the
14		no-risk design, customers who are uncomfortable with the design of other demand
15		response programs may be drawn to this pilot. Based on benchmark findings, the
16		no-penalty design of the PTS pilot should broaden the program reach amongst the
17		DTE Electric customer base, influence high participation and retention rates, and
18		increase customer satisfaction. Participating customers who reduce their energy
19		consumption during the called events will also benefit from reduced energy bills
20		through bill credits.
21		

## 22 Q55. What was the original design of the pilot?

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A55. Within the original pilot design, Peak Time Events are called on weekdays from 3
p.m. to 7 p.m., excluding holidays, during all four seasons of the year with a
maximum of 14 occurrences (or 56 hours) in a calendar year. Customers are

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notified of events by 6 p.m. the day prior via email and/or text, based on their preferences selected upon enrollment in the pilot, as well as receive reminders prior to the start and end of each event. Following each event, the Company will assess the impact on peak savings by comparing the customers' actual electricity usage during the event to a pre-determined baseline calculated based on a set of the highest non-holiday weekday usage in prior periods.

- 8 The PTS pilot is designed to test different variable sets during its two phases to 9 inform the design of a potential full-scale program. First, during the customer 10 acquisition phase, the pilot tested three sets of marketing and outreach variables 11 (i.e., three rebate levels, two benefit messages, and various outreach channels) to 12 determine which combinations result in the highest opt-in rates. Then, during the 13 event phase, the pilot is testing the responsiveness of different customer groups 14 (i.e., high technical potential, low-income, and mixed potential / mixed income) to different rebate levels. The pilot has developed comprehensive webpages for the 15 16 Company to provide customers with an overview of the program and answer 17 common questions, automatically process enrollments completed via self-service, 18 collect and maintain customer event notification preferences, and provide an 19 educational connection point for pilot participants, for instance when they need 20 savings tips to reduce usage during events or when they'd like to review their 21 individual event performance. Additionally, the pilot offers a dedicated team of 22 customer service advisors specifically trained to answer all PTS questions and 23 complete enrollment or unenrollment on behalf of the customer.
- 24
- 25 Q56. What did the Company observe in the first year of the pilot?

Line
<u>No.</u>

1	A56.	The Company launched the PTS pilot recruitment in Summer 2021 with the first
2		invitations sent in June 2021, coinciding with the first summer event season.
3		Throughout the complete customer acquisition phase, the PTS pilot was offered to
4		approximately 450,000 residential electric customers to "opt-in" to the pilot with
5		the goal of obtaining 10,800 eligible participants based on performance of other
6		DTE pilots. The pilot concluded recruitment on December 31, 2021, with 10,994
7		participants. As of December 31, 2022, the PTS has 9,748 customers enrolled in
8		the pilot. Approximately 27% of pilot participants are considered low-income.
9		
10		The first event season began in Summer 2021 with the first Peak Time Event called
11		on August 25, 2021, with 2,235 customers enrolled at the time of the event.
12		Effectiveness of the two key messages, environmental versus cost savings-focused,
13		was essentially the same; however, email proved to be the strongest converting
14		channel with approximately 93% of enrollments coming from an email campaign.
15		Overall, the pilot is now scheduled to conclude at the end of September 2023. At
16		that time, the pilot will be fully evaluated to determine the next steps, which could
17		include, but are not limited to, continuing the pilot, continuing the pilot with
18		modifications, or discontinuing the pilot. Participants will be notified of any
19		outcomes.

# Q57. What load reductions and customer savings has the Company seen in the first year of the PTS pilot?

A57. The Company called one (1) event in 2021 and seven (7) events in 2022 as of
December 31, 2022. To date, an event has been called within each of the four (4)

		K. O. FARRELL
Line <u>No.</u>		U-21297
1		seasons, Fall, Winter, Spring and Summer. The average reduction has been 1.2 kWh
2		with customers saving an average \$1.10 per event via bill credit.
3		
4	Q58.	Are you making any changes to the design of the PTS Pilot in Year 2?
5	A58.	Yes. Pilot changes tentatively planned for January 2023 include, but are not limited
6		to, the following:
7		• Modifying the event notification window to increase flexibility for potential
8		day-of events,
9		• Increasing the number of Peak Time Events from 14 events per calendar
10		year to 20 events,
11		• Expanding eligibility to assess pairing PTS with BYOD, as well as allowing
12		compatibility with the new Time of Day rate (D1.11) and the Senior Citizen
13		Credit, and
14		• Issuing a flat credit of \$3 in the instance of insufficient usage data during
15		the credit calculation process.
16		The pilot will be extended through September 2023 to allow the Company adequate
17		time to assess the changes to the pilot.
18		
19	Q59.	What has been the pilot participants' reception to the PTS Pilot?
20	A59.	The Company surveyed participants in May 2022 to gauge customer satisfaction
21		and perception of the pilot. Forty-six percent of customers are satisfied with the
22		PTS pilot (top-2-box, noting a satisfaction score of 9 or 10.), with an average
23		satisfaction rating of 7.8 on a 10-point scale. When asked, most participants
24		indicated they enrolled in PTS to save on their energy bill; on a sliding scale, more
25		customers lean towards saving money as the reason for enrollment (64%) versus

1 helping the environment (36%). However, those who join to help the environment 2 are more satisfied with PTS than those who joined to save money. When asked 3 what is going well with the pilot, many cited notifications of events, the idea of 4 saving energy and money, explanations on how to reduce energy consumption, and 5 ease of participation. Opportunities for improvement noted by participants 6 surveyed include more timely and detailed explanations of savings, increased 7 savings for participation, and more frequent events. Seventy-seven percent (Figure 8 1) of participants felt that the pilot met or exceeded their expectations, with 46% 9 (Figure 2, ratings 9 + 10) would recommend it to their friends or colleagues. 10

Line

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2

4 Q60. How is PTS being evaluated for viability as a full scale program?

5 A60. To evaluate the viability of PTS as a full-scale program, the Company will continue to assess peak demand reduction for each season and overall energy use impacts 6

1

101		
1		and will monitor customer engagement in the acquisition phase based on available
2		marketing metrics. Additionally, the Company plans to conduct consumer research
3		to assess customers' overall experience and likelihood to recommend, satisfaction
4		ratings and motivational factors.
5		
6	Q61.	How much is the Company forecasting to invest in the Peak Time Savings pilot
7		going forward?
8	A61.	The Company is forecasting to spend \$0.3 million in capital during the bridge
9		period and \$0.5 million in capital during the projected test year ending November
10		30, 2024, in support of the PTS pilot.
11		
12	Q62.	Has the Commission previously supported the development of the Peak Time
13		Savings pilot?
14	A62.	Yes. The Commission supported the PTS pilot in the 2022 Electric Rate case (U-
15		20836). In addition, the PTS pilot was supported by Staff through settlements in
16		the DR Reconciliation cases (U-20793, U-21044 and U-21242).
17		
18	Batter	y Energy Storage Pilot
19	Q63.	Could you describe the Company's battery energy storage pilot for C&I
20		customers?
21	A63.	Yes. The battery energy storage pilot, which was previously discussed in U-20836,
22		is a behind-the-meter (BTM) lithium ion phosphate battery energy storage system
23		(BESS) at two customers' sites. It is designed to test the ability to achieve peak
24		demand shaving or shifting during demand response events. As part of the
25		implementation plan, the Company has identified one very interested customer and

Line <u>No.</u>		K. O. FARRELL U-21297
1		has engaged in active dialogue with the customer. A second customer has not yet
2		been identified.
3		
4	Q64.	What are the main objectives of the BTM battery energy storage pilot?
5	A64.	The main objectives of the designed pilot are as follows:
6		• Evaluate the effectiveness of the BESS to achieve system peak demand
7		reduction when a demand response event is called by the Company;
8		• Assess customer's actions to achieve demand charge and overall bill
9		reduction;
10		• Gain operational experience on battery installation, management, and
11		control interfaces when the system is located in a customer's site as opposed
12		to a Company's site;
13		• Engage with customers to better understand their interest in hosting and
14		potentially escalating BESS;
15		• Assess feasibility for sharing asset control between customer and the
16		Company; and
17		• Facilitate the understanding of multiple energy storage values,
18		compensation models, and the integration of battery storage in wholesale
19		markets to support tariff development as contemplated by the
20		Commission's order in MPSC Case No. U-21032.
21		
22	Q65.	What are the customer benefits of participating in the BTM battery energy
23		storage pilot?
24	A65.	The pilot will target customers who are already enrolled on the Company's Rate
25		D4, Rate D6.2, or Rate D11 electric tariffs (excluding sites or load under Rider 10)

## KOF-33

1 since those customers are more suited for pilot participation due to their peak load 2 profiles, outdoor space availability and operational capabilities. The Company will 3 retain the ability to control the BESS when calling a dispatch event while the 4 customer will retain the option to use the BESS when the Company does not call 5 an event. The dispatch strategy will consider the ability for the Company to call a 6 certain number of scheduled DR events with a prior-day notification, and a limited 7 number of emergency DR events with immediate notification. When no Company 8 DR event is planned, the customer will be able to dispatch the BESS to address its 9 facility energy needs on a day-by-day basis. It is expected that more detailed 10 commercial arrangements will balance the different control and use possibilities 11 split between the Company and the customer. This arrangement will allow for the 12 customer to get experience operating a battery while potentially reducing peak 13 operating costs.

14

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#### 15 Q66. What are the estimated impacts of the BTM battery energy storage pilot?

A66. While the design parameters are subject to change as the Company moves forward
with the pilot engaging the customer host, the battery will be up to 250 kW/1 MWh
at each of potentially two sites to reduce peak customer and system demand over
an event of up to 4 hours.

20

## Q67. When will the implementation plan for the BTM battery energy storage pilot take place?

A67. The Company has conducted the RFP with additions of detailed requests for
adherence to strict fire safety standards, equipment delivery time, and updated costs
for more specific pilot siting or siting's within the Company's service territory. The

1	Company received bids from six integrators and has ultimately finalized its
2	selection of a specific equipment provider and integrator, Hitachi, based on
3	information gathered from the Request for Proposal (RFP) process. Hitachi's
4	proposal includes a skid-based solution, with integration of the equipment upfront,
5	subsequently lowering the on-site installation cost(s). The installation is forecasted
6	to take place in 2023 based on the potential need of equipment testing for safety
7	and configuration with DTE Electric's systems, and on the commercial
8	arrangement with the host customer(s).

#### 10 **Q68.** How will the BTM battery energy storage pilot be evaluated?

11 A68. The BTM battery energy storage pilot will be evaluated by measuring the load 12 reduction during events called by the Company against the battery expected 13 parameters, as well as the evaluation of other system impacts. The customer peak 14 load reduction will also be evaluated to observe the reduction on the customer's bill 15 for both Company called events and customer's use. The Company will also 16 evaluate communication and sharing of the battery controls with a customer.

17

## 18 **Q69.** Will this battery storage pilot facilitate the understanding of multiple energy

storage values, compensation models, and the integration of battery storage in
wholesale markets to support tariff development as contemplated by the
Commission's order in U-21032?

A69. Yes. The Commission's August 11, 2021, Order in Case No. U-21032 encourages
utilities to propose, in upcoming rate cases, "well-designed retail tariffs that account
for the full value stack ESRs (energy storage resources) offer, while also allowing
for participation through the utility in regional wholesale markets" (Order at p. 27).

1 The order contemplates utilities participating in wholesale electricity markets on 2 behalf of customer-owned ESRs. In order to develop such tariffs and related pilot 3 programs for customer-owned battery storage, the Company needs to gain 4 experience with the application of storage technology by end use customers and 5 interactions with the wholesale market. The proposed energy storage pilot will 6 provide data and other learnings on the services and values battery storage can 7 provide to end use customers and the utility and how storage can be paired with 8 complementary programs such as demand response to maximize value and 9 optimize operation of energy storage. The energy storage applications in this pilot 10 will serve an energy management function for the participating customers to help 11 reduce electricity bills while also providing services when needed by the utility to 12 support reliability in the bulk power system. Quantifying how the storage is used, 13 the associated values it brings to the customer and the Company, direct and indirect 14 costs, and coordination between the customer and the Company will help the 15 Company develop appropriate tariffs and compensation models as contemplated by 16 the Commission. The Company expects to engage further with the Commission and 17 stakeholders to develop such tariffs using data from the pilot.

18

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## Q70. Did the Commission support the spending associated with the C&I Battery Storage pilot in the most recent rate case, U-20836?

- A70. Not entirely. Following Staff's recommendation in U-20836 where Staff supported
  the idea of the pilot but believed the pilot lacked specific detail to support the
  spending associated with it, the Commission similarly supported the pilot idea but
  ultimately disallowed the associated spending.
- 25

#### 1 Q71. Has there been any further developments in the design of C&I Battery 2 Storage pilot since the last rate case? 3 A71. Yes. The batteries have been ordered and shipped from China and have arrived in 4 the US. The Company has ordered all other major equipment for the BESS. The 5 prospective customer intends to leverage the battery to reduce peak demand 6 charges. The Company will also leverage the battery for demand response events. 7 The initial proposed event schedule includes no more than 30 planned demand 8 response events per year and 5 emergency demand response events, with a least 9 one-hour customer notice, per year. The contractual agreement with the prospective 10 customer is anticipated to be executed by the second quarter of 2023. Options for 11 the customer to purchase or lease the BESS post pilot will be integrated into the 12 customer agreement regardless of pilot or program continuation. 13 14 Q72. How much capital is the Company forecasting to spend in support of the C&I 15 Battery Storage during the bridge period of January 1, 2022 through 16 November 30, 2023, and in the projected test year ending on November 30, 17 2024? 18 A72. The Company is forecasting to spend \$4 million in capital during the bridge year 19 and another \$0.2 million in capital during the projected test year. 20 21 **Residential Generator Pilot** 22 073. Could you describe the Company's residential generator pilot? 23 A73. Yes. The Company plans to conduct a residential customer-owned natural gas 24 generator pilot, which was previously introduced in U-20836. The pilot will

25 leverage Generac Grid Services' platform and utilize telemetry to shift customers'

#### Line <u>No.</u>

## KOF-37

Line		K. O. FARRELL U-21297
<u>No.</u>		
1		electric load to the customers' generator in real-time during peak events. Customers
2		will receive an incentive for their participation in the program.
3		
4	Q74.	What are the general objectives in pursuing a residential generator pilot?
5	A74.	The main objectives of the residential generator pilot are as follows:
6		• Assess the viability of a program that can act as a year-round DR asset
7		responding on short-term notices for peak events;
8		• Determine whether customers would be willing to participate actively and
9		allow for real-time telemetry to control their generators during an event;
10		• Measure how effective the customer-owned generators respond as a year-
11		round LMR;
12		• Assess customer receptiveness and the value customers receive from a
13		residential generator pilot; and
14		• Identify and process new learnings that could be applied to current and
15		future demand response offerings.
16		
17	Q75.	What are the customer benefits of participating in the residential generator
18		pilot?
19	A75.	Pilot participants will benefit by receiving incentives from the Company which
20		include an up-front gift card of \$100 and a \$250 gift card for remaining enrolled at
21		the end of the pilot term as well as reduced electric bills during peak events.
22		
23	Q76.	What is the estimated impact of the residential generator pilot for the pilot
24		duration?

1	A76.	Through early analysis, it is estimated that there are at least 43,000 eligible
2		residential generators with an estimated impact of 3.5- 5kW of load reduction per
3		unit. The Company is initially targeting 200 customer enrollments over a minimum
4		two-year pilot period.
5		
6	Q77.	What is the status of the implementation plan of the residential generator
7		pilot?
8	A77.	The Company has selected Generac Grid Services through the Request for
9		Information (RFI) process. Generac Grid Services was selected based on the
10		comprehensive turnkey solution they proposed, their demand response program
11		experience, and their large presence in the home standby generator market offering
12		a less expensive path to market. Marketing efforts and customer enrollment is
13		planned to begin in the first quarter of 2023.
14		
15	Q78.	How will the residential generator pilot be evaluated?
16	A78.	The Company intends to have the following metrics in place and tracked to evaluate
17		pilot effectiveness: customer acquisition and enrollment rates (including attrition),
18		marketing metrics (outreach activities and their impact), and load shed during
19		different type of events.
20		
21	Q79.	Did the MPSC Staff and Commission support the spending associated with the
22		residential generator pilot in the most recent rate case, U-20836?
23	A79.	No, MPSC Staff argued the Commission should disallow the spending associated
24		with the residential generator pilot because they were concerned the pilot was not
25		yet well developed, which the Commission ultimately ordered.

Line <u>No.</u> Line <u>No.</u>

- 1
- 2 Q80. Has there been any further developments in the design of residential
  3 generator pilot since the last rate case?

4 A80. Yes, the generator pilot will target customers with a Generac Smart Grid Ready 5 (SGR) generator, which are capable of remote operations and responding to grid 6 events via Generac's mobile/web-based application, Mobile Link Premium. A 7 Mobile Link Premium subscription is required to participate in the pilot. The 8 Company intends to provide a coupon code for eligible customers for a free 9 subscription if they do not already have an existing account. Demand response 10 event parameters for the pilot have yet to be determined, but initial design event window is between the hours of 8:00 AM - 8:00 PM on weekdays, excluding 11 12 holidays, and duration will not exceed 4 hours per event and 40 hours annually. The 13 pilot is designed to remove the entire home load during a demand response event 14 and can be called with no less than 30-minute advance notice. Customers will be 15 incentivized with a gift card offering, but the final incentive amount has not been 16 determined at this time.

17

In addition, the Company acted upon Staff's recommendation and benchmarked with Consumers Energy on their residential generator pilot to get their feedback and learnings from their experiences. After speaking with Consumers Energy, the Company used the learnings from the conversations to make some modifications to the Company's pilot.

23

Q81. How much capital and O&M is the Company forecasting to spend in support
 of the residential generator pilot during the bridge period of January 1, 2022

Line <u>No.</u>

1		through November 30, 2023, and in the projected test year ending on
2		November 30, 2024?
3	A81.	The Company is forecasting to spend \$0.2 million in capital over the bridge period
4		and the forecasted test year to support the pilot. The Company also is forecasting
5		to spend \$0.2 million annually in O&M to support the pilot.
6		
7	Water	heater control unit replacement program
8	Q82.	Could you elaborate on the plans to replace water heating control units?
9	A82.	Yes. The Company plans to begin the replacement of approximately 46,000
10		residential and commercial water heating load control units for customers who
11		currently take service under the water heating service rate of D5 in 2023. By taking
12		service under this separately metered rate, customers' water heating units can be
13		interrupted remotely by the Company in exchange for a discounted energy charge
14		for the associated usage. Similar to the reasons behind the IAC replacement project,
15		the Company has identified that the original LCD units that currently reside in
16		customers' homes have reached the end of life and no longer function as intended.
17		The pilot will also study the feasibility of recruiting new customers onto the
18		interruptible water heating rate.
19		
20	Q83.	What are the general objectives in replacing the water heating control units?
21	A83.	By investing in a water heating control unit replacement program, the Company is
22		able to extend the equipment life as well as increase the available capacity in MISO.
23		This program also provides an additional demand response program option for
24		residential and commercial customers.

25

Line <u>No.</u>		<b>K. O. FARRELL</b> U-21297
1	Q84.	Did the Commission support the spending associated with the water heating
2		replacement project in the most recent rate case, U-20836?
3	A84.	Yes. Following Staff's recommendation, the Commission supported the project.
4		
5	Q85.	How much capital and O&M is the Company forecasting to spend in support
6		of the water heating replacement project during the bridge period of January
7		1, 2022 through November 30, 2023, and in the projected test year ending on
8		November 30, 2024?
9	A85.	The Company is forecasting to spend \$1.1 million in capital over the bridge period
10		and the projected test year to support the pilot. The Company also is forecasting to
11		spend \$0.2 million annually in O&M to support the project.
12		
13	<u>Comn</u>	nercial and Industrial Dashboard Technology
14	Q86.	What is the Commercial and Industrial (C&I) Dashboard Technology that the
15		Company would like to provide interruptible customers?
16	A86.	The Company is planning to partner with a program implementer to provide C&I
17		customers who take service under a demand response tariff (i.e. D8, R10 and R12)
18		with technology and software so customers can better understand, and sequentially,
19		improve upon their event performance. In addition, the technology can provide
20		more advanced analytics for better DR forecasting for the Company to provide to
21		MISO. An RFI was conducted in November of 2022 and is currently being
22		evaluated to determine next steps.
23		
24	Q87.	How can the C&I Dashboard Technology assist customers during
25		interruptible events?

1	A87.	The technology provides real time telemetry to the customer and the Company, so
2		the event performance is monitored in real time and displayed on a dashboard for
3		the participating customer and the Company. This instantaneous feedback lets both
4		the customer and the Company know if additional actions need to be taken to reduce
5		load to committed levels. In addition, the technology provides more advanced
6		analytics for better DR forecasting and post-event analysis.
7		
8	Q88.	Did the Commission support the spending associated with the replacement
9		Dashboard Technology project in the most recent rate case, U-20836?
10	A88.	Yes. Following Staff's recommendation, the Commission supported the project.
11		
12	Q89.	How much capital is the Company forecasting to spend in support of the water
13		heating replacement project during the bridge period of January 1, 2022
14		through November 30, 2023, and in the projected test year ending on
15		November 30, 2024?
16	A89.	The Company is forecasting to spend \$0.3 million in capital over the bridge period
17		and \$0.4 million the projected test year to support the project. The Company also
18		is forecasting to spend \$0.1 million annually in O&M to support the project.
19		
20	Q90.	Does this complete your testimony?
21	A90.	Yes.

## STATE OF MICHIGAN

## BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)
DTE ELECTRIC COMPANY	)
for authority to increase its rates, amend	)
its rate schedules and rules governing the	)
distribution and supply of electric energy, and	)
for miscellaneous accounting authority.	)

Case No. U-21297

## QUALIFICATIONS

## AND

## DIRECT TESTIMONY

OF

## NEAL T. FOLEY

## DTE ELECTRIC COMPANY QUALIFICATIONS AND DIRECT TESTIMONY OF NEAL T. FOLEY

Line <u>No.</u>

101		
1	Q1.	What is your name, business address and by whom are you employed?
2	A1.	My name is Neal T. Foley (he/him/his). My business address is One Energy Plaza,
3		Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC,
4		a subsidiary of DTE Energy Company as Director, Regulatory Affairs.
5		
6	Q2.	On whose behalf are you testifying?
7	A2.	I am testifying on behalf of DTE Electric Company (DTE Electric or Company).
8		
9	Q3.	What is your educational background?
10	A3.	I received a Bachelor of Science in Aerospace Engineering and a Bachelor of
11		Science in Mechanical Engineering from the University of Michigan. I also
12		received a Master of Science in Systems Engineering from Johns Hopkins
13		University and a Master of Business Administration from Georgetown University.
14		
15	Q4.	What is your work experience?
16	A4.	In 2007 I was employed by Lockheed Martin Corporation as a Satellite Operations
17		Engineer. In 2008, I was hired by Booz Allen Hamilton as an Associate Consultant
18		in its Federal consulting practice. In 2012, I was hired by Deloitte as a Manager of
19		Financial Analysis in its Federal consulting practice. In 2014, I was hired by
20		McKinsey & Company as an Associate Consultant, ultimately being promoted to
21		Engagement Manager before my departure in 2017. In 2017 I was hired by DTE
22		Energy Company as Manager of Corporate Strategy. In this role I was broadly
23		responsible for tracking and assessing utility industry trends, executing analyses to
24		better understand the economic impacts of emerging technologies and business

		N. T. FOLEY
Line <u>No.</u>		U-21297
1		models, and leading strategic initiatives for the Company. I was promoted to my
2		current role as Director of Regulatory Affairs in 2020.
3		
4	Q5.	What are your current duties and responsibilities?
5	A5.	My responsibilities broadly include the management of regulatory activities
6		relative to DTE Electric's Load Research, Tariffs, Pricing, and Rate Design.
7		
8	Q6.	Have you previously sponsored testimony before the Michigan Public Service
9		Commission (MPSC or Commission)?
10	A6.	Yes. I have sponsored testimony in the following case:
11		U-20836 DTE 2022 Electric Rate Case
12		

## 1 **Purpose of Testimony**

### 2 Q7. What is the purpose of your testimony in this proceeding?

A7. The purpose of my testimony is to describe the key components of a proposal that
the Company is putting forth in this case for the establishment of a Distribution
Infrastructure Recovery Mechanism (Distribution IRM or IRM) focused on
strategic capital programs related to customer safety and reliability. As such, my
testimony is separated into the following sections:

IRM history, motivation, and benefits. In this section I describe the recent
 history of IRMs at the Company, the motivation for the Company proposing
 a Distribution IRM in this case, and the benefits that will be realized through
 the establishment of the proposed IRM.

12 IRM scope and surcharge. In this section I describe the scope of the proposed Distribution IRM, including the selection of included capital 13 14 programs and the associated annual capital investment. The Company's 15 proposal in this area is further supported by Company Witnesses Deol, 16 Elliott Andahazy, and Hill. I also describe the calculation and application 17 of IRM surcharges, and how the Company proposes to calculate and address 18 any over-recovery of costs. The Company's proposal in this area is further 19 supported by Company Witnesses Vangilder, Maroun, and Willis.

IRM annual processes. In this section I describe the annual processes that
 the Company is proposing to establish as part of the Distribution IRM
 related to planning, reporting, and reconciliation. I also describe the
 relationship between the proposed IRM and future general rate cases.

• IRM program execution metrics. In this section I describe the program-25 specific execution metrics that the Company is proposing to begin reporting

••					<b>N.</b>	T. FOLEY
Line <u>No.</u>						U-21297
1		as part of	of its Distribution IRM	A. The Company's pr	roposal in	this area is
2		further s	upported by Company	Witnesses Deol, Ellio	ott Andahaz	zy, and Hill.
3						
4	Q8.	Are you sponse	oring any exhibits in t	his proceeding?		
5	A8.	Yes. I am spons	oring the following ex	hibit:		
6		<u>Exhibit</u>	<u>Schedule</u>	<b>Description</b>		
7		A-33	X1	Distribution	IRM	Proposed
8				Investment and	In-Service	e Levels
9						
10	Q9.	Was this exhib	it prepared by you or	under your direction	n?	
11	A9.	Yes, it was.				
12						
13	Distri	bution IRM – H	istory, Motivation, an	d Benefits		
14	Q10.	Can you pleas	e describe the basic	structure of an Infr	astructur	e Recovery
15		Mechanism (IF	RM)?			
16	A10.	An IRM is a reg	ulatory tool that allows	a utility to recover the	e costs asso	ociated with
17		certain capital i	nvestments made on	behalf of its customer	rs between	rate cases.
18		IRMs typically	have a clearly defined	duration, size, and sco	pe such the	at the utility
19		is limited to spe	cific investments that i	t can make under the	IRM const	ruct.
20						
21		Capital investme	ent that is authorized for	or IRM treatment is in	itially han	dled outside
22		of the Compan	ny's overall rate base	. Instead, an IRM h	as its ow	n rate base
23		comprised of ca	pital that was invested	and put into service	under the	IRM. Much
24		like the Compa	any's overall rate bas	e, the IRM rate base	e grows as	s new IRM
25		investments are	made and put into se	ervice and shrinks as	those inve	stments are

depreciated. Likewise, the IRM has its own revenue requirement derived from the
 IRM rate base.

Given this structure, the capital invested under the IRM is not initially recovered through a utility's base rates but is instead recovered through a separate IRM surcharge. Similar to how the Company's base rates are designed to recover the costs of the Company's overall rate base (among other things), an IRM surcharge is designed to recover the costs of the Company's IRM rate base.

9

In a future general rate case, the capital invested and put into service under the IRM is transferred from the IRM rate base to the Company's overall rate base. Thus, the revenue requirement associated with the capital invested under the IRM is rolled into base rates, and the IRM surcharge is reset. At that point, the Company could seek approval of an extension and/or modifications to the IRM for incremental capital investments.

16

17 To establish an IRM, the Company receives approval from the Commission to 18 recover the costs associated with specific future capital investments through IRM 19 surcharges. As such, the amount of the IRM surcharges for the projected test year 20 and beyond will be established in the instant case. The Company cannot unilaterally 21 increase the surcharges above what is approved in the instant case, but any over-22 recovery due to IRM underinvestment will be returned to customers. By receiving 23 this approval for cost recovery, an IRM allows the Company to recover the costs 24 for the IRM capital programs in between rate cases.

25

N. T. FOLEY		
U-21297		Line <u>No.</u>
Of note, the IRM will be subject to audit and review, as I will describe later in my		1
testimony. As such, the structure of the IRM is appropriate and consistent with		2
previously approved mechanisms.		3
		4
11. Can you please describe the recent history related to IRMs at the Company?	Q11.	5
11. In Case No. U-20162, the Company proposed the establishment of an IRM focused	A11.	6
on its distribution system, fossil generation assets, and nuclear generation assets.		7
The investments proposed for IRM treatment would have encompassed roughly		8
\$2.8 billion of capital over roughly two and a half years after the projected test year		9
in that case. While the Commission rejected the Company's proposed IRM in that		10
case, it provided in part the following guidance in its Order on May 2, 2019 (May		11
2019 Order):		12
		13
"The Commission is receptive to considering an IRM with the proper oversight,		14
legal structure, and performance-based regulation framework including		15
customer protections." (page 117)		16
		17
In Case No. U-20836 the Company did not propose the establishment of an IRM,		18
but the Commission provided in part the following guidance in its Order on		19
November 18, 2022 in that case (November 2022 Order):		20
		21
"The Commission cannot stress enough its expectation that DTE Electric will		22
invest the amounts approved for strategic capital improvements and not shift		23
them to other categories such as emergent replacement and other reactive		24
spending. As such, the Commission may be willing to consider a long-term		25

1		investment recovery mechanism (similar to the Infrastructure Recovery
2		Mechanism for the gas Main Renewal Program first approved in the April 16,
3		2013 order in Case No. U-16999) to ensure that the spending included in rates
4		for strategic capital improvements - including the ultimate conversion of DTE
5		Electric's distribution grid - is spent for these purposes, and to provide greater
6		long-term certainty on recovery of reasonable and prudent costs related to these
7		strategic distribution grid investments. The Commission expects that DTE
8		Electric will include in any such proposal a full description of costs and
9		benefits, as well as associated timelines." (pages 76-77, emphasis added)
10		
11	Q12.	Why is the Company proposing to establish a Distribution IRM in the instant
12		case?
13	A12.	The Company believes that the proposed Distribution IRM put forward in my
13 14	A12.	The Company believes that the proposed Distribution IRM put forward in my testimony is responsive to Commission guidance and represents a further
13 14 15	A12.	The Company believes that the proposed Distribution IRM put forward in my testimony is responsive to Commission guidance and represents a further commitment by the Company to improve the customer safety and reliability of its
13 14 15 16	A12.	The Company believes that the proposed Distribution IRM put forward in my testimony is responsive to Commission guidance and represents a further commitment by the Company to improve the customer safety and reliability of its distribution system.
13 14 15 16 17	A12.	The Company believes that the proposed Distribution IRM put forward in my testimony is responsive to Commission guidance and represents a further commitment by the Company to improve the customer safety and reliability of its distribution system.
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> </ol>	A12.	The Company believes that the proposed Distribution IRM put forward in my testimony is responsive to Commission guidance and represents a further commitment by the Company to improve the customer safety and reliability of its distribution system. More specifically, based on feedback offered by the Commission and other
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> </ol>	A12.	The Company believes that the proposed Distribution IRM put forward in my testimony is responsive to Commission guidance and represents a further commitment by the Company to improve the customer safety and reliability of its distribution system. More specifically, based on feedback offered by the Commission and other stakeholders, the Company seeks to achieve the following through its proposed
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> </ol>	A12.	The Company believes that the proposed Distribution IRM put forward in my testimony is responsive to Commission guidance and represents a further commitment by the Company to improve the customer safety and reliability of its distribution system. More specifically, based on feedback offered by the Commission and other stakeholders, the Company seeks to achieve the following through its proposed Distribution IRM:
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> </ol>	A12.	The Company believes that the proposed Distribution IRM put forward in my testimony is responsive to Commission guidance and represents a further commitment by the Company to improve the customer safety and reliability of its distribution system. More specifically, based on feedback offered by the Commission and other stakeholders, the Company seeks to achieve the following through its proposed Distribution IRM: • Increased accountability for the Company to fully execute its strategic
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> </ol>	A12.	The Company believes that the proposed Distribution IRM put forward in my testimony is responsive to Commission guidance and represents a further commitment by the Company to improve the customer safety and reliability of its distribution system. More specifically, based on feedback offered by the Commission and other stakeholders, the Company seeks to achieve the following through its proposed Distribution IRM: • Increased accountability for the Company to fully execute its strategic investments critical to customer safety, reliability, and resiliency deemed

Line <u>No.</u>		U-21297
1		• Increased transparency into the Company's investment plans and timelines,
2		and the execution of those plans, beyond the projected test year typically
3		assessed during a general rate case; and
4		• Increased opportunities for Michigan Public Service Commission Staff
5		(Staff) to review and provide input on the Company's distribution
6		investment plans.
7		
8	Q13.	What benefits would be realized through the establishment of the proposed
9		Distribution IRM?
10	A13.	The Distribution IRM would deliver a variety of benefits to the Company's
11		customers and stakeholders, as well as support the Commission's previously stated
12		desire to achieve a "more thorough understanding of anticipated needs, priorities,
13		and spending." <sup>1</sup>
14		
15		More specifically, the Company has identified four key benefits of a Distribution
16		IRM that would be immediately realized if such a mechanism were to be
17		established, and one additional benefit that could be realized in the future.
18		
19		First, the Distribution IRM would provide certainty of investment in key
20		distribution capital programs focused on customer safety, customer reliability, and
21		the integration of increasing levels of Electric Vehicles (EVs) and other Distributed
22		Energy Resources (DERs). It also directly responds to the Commission's
23		expectation that "DTE Electric will invest the amounts approved for strategic
24		capital improvements and not shift them to other categories" (November 2022

<sup>&</sup>lt;sup>1</sup> January 31, 2017 order in Case No. U-18014 (page 41)

Line No.

> 1 Order, pages 76-77). As described above, a Distribution IRM would authorize IRM 2 treatment for specific strategic capital programs, and up to a certain level of capital 3 investment for each program. Both the amount of investment receiving IRM 4 treatment, and the specific programs associated with the Distribution IRM would 5 be approved by the Commission for cost recovery in the instant case, or in future 6 contested rate cases if incremental IRM capital investment was proposed at that 7 time. As such, the approval of a Distribution IRM in effect establishes a dedicated 8 funding source for critical distribution capital programs deemed prudent and 9 reasonable by the Commission. The Company would only be able to recover its 10 capital costs between rate cases for the specific capital programs approved for the 11 IRM, and only up to the amount authorized for IRM treatment. The Company 12 would not be able to recover its capital costs between rate cases for programs not 13 covered by the IRM, or if the Company shifts investment amounts between 14 programs associated with the IRM. Importantly, any underinvestment in the 15 programs associated with the IRM would be returned to customers, offering the 16 appropriate customer protections requested by the Commission.

17

18 Second, the Distribution IRM would provide greater transparency into both the 19 Company's investment plans and its execution of those plans. As I will describe 20 later in my testimony, the Company proposes to establish an annual "IRM Planning 21 Process" that would provide Staff with greater detail about the Company's 22 investment plans for the upcoming year. Among other things, the proposed 23 planning process would provide information pertaining to planned projects and 24 their associated costs, and the selection criteria used to identify those planned 25 projects. Likewise, the Company is also proposing an annual "IRM Reconciliation
2

3

4

5

Process". As I will describe later in my testimony, this process would provide information pertaining to the Company's execution of its investment plan, including projects completed versus what was planned and actual project costs versus what was estimated.

6 Third, the Distribution IRM would provide Staff with additional opportunities to 7 review and provide input on the Company's investment plans. As part of the 8 proposed IRM Planning Process that I will describe later in my testimony, Staff 9 would have the opportunity to provide feedback on the Company's investment 10 plans for the upcoming year. The Company would then have an opportunity to 11 address that feedback and respond to any questions or concerns raised by Staff 12 before beginning execution of its plans.

13

Finally, the Distribution IRM would result in increased accountability for the Company. As part of the IRM Reconciliation Process that I will describe later in my testimony, the Company is proposing to begin reporting new program execution metrics, designed to specifically assess the execution of the Company's investment plans.

19

In addition to the four benefits described above that would be immediately realized once the Distribution IRM becomes effective, a potential future benefit of an IRM is the ability to extend the time between contested rate cases. By authorizing sustained IRM treatment for critical distribution capital programs beyond a contested rate case projected test year, it may be possible for the Company to delay the filing of future general rate cases. Extending the time between contested rate

1		cases can have a variety of benefits for all involved stakeholders, such as reduced
2		administrative burden and costs, and making available organizational resources to
3		focus on other key customer priorities. Although the Company is not proposing a
4		"stay out" provision as part of its proposal in the instant case, it does view extending
5		the time between general rate cases as a longer-term objective of the Distribution
6		IRM.
7		
8	Q14.	Does DTE Energy have existing IRMs in use today?
9	A14.	Yes, DTE Energy's gas utility (DTE Gas) utilizes an IRM to recover the costs of
10		certain capital investments that support the safety and reliability of the gas
11		distribution system. The programs associated with the DTE Gas IRM include the
12		replacement of aging cast- and wrought-iron and bare and unprotected steel main,
13		the relocation of gas meters from the inside of customer homes and business to
14		outside locations, and DTE Gas's pipeline integrity program. The Commission first
15		approved IRM treatment for these programs in 2013 <sup>2</sup> , including an annual
16		investment of \$77 million. Since that initial authorization, the size of the DTE Gas
17		IRM has increased to \$287 million in annual investment.
18		
19		The DTE Gas IRM uses an annual planning process by which the Company makes
20		available to Staff its investment plans for the following year, including planned
21		projects and estimated costs. Likewise, the DTE Gas IRM also uses an annual
22		reconciliation process by which the Company reports its actual investments for the
23		previous year, including a reconciliation between planned and actual investment.
24		As part of this process, the Company also reports program execution metrics.

<sup>&</sup>lt;sup>2</sup> See the April 16, 2013 order in Case No. U-16999

Line		<b>N. T. FOLEY</b> U-21297
<u>No.</u>		
1		
2	Q15.	Is the Company's proposed Distribution IRM similar to the DTE Gas IRM?
3	A15.	Yes. In its November 2022 Order the Commission specifically referenced the DTE
4		Gas IRM when it discussed a potential DTE Electric IRM, stating:
5		
6		"the Commission may be willing to consider a long-term investment
7		recovery mechanism (similar to the Infrastructure Recovery Mechanism for the
8		gas Main Renewal Program" (page 77, emphasis added)
9		
10		Given this guidance, the Company based much of its proposed Distribution IRM
11		on the DTE Gas IRM referenced by the Commission. For example, as I discuss
12		later in my testimony, the Company is proposing to establish both a planning and a
13		reconciliation process as part of its Distribution IRM modeled after the DTE Gas
14		IRM processes.
15		
16	Q16.	Is the Company proposing the Distribution IRM as part of a broader
17		Performance-Based Regulation (PBR) proposal with financial incentives and
18		penalties?
19	A16.	No. As I discuss later in my testimony, the Company is proposing to begin reporting
20		new program execution metrics as part of the Distribution IRM. These metrics will
21		help Staff and the Commission monitor the Company's execution of its IRM
22		investment plans.
23		

<b>N. T. FOLE</b> U-2129
As it relates to the establishment of a broader PBR program, in its September
2022 Order in Case No. U-20147 (September 2022 Order), the Commission
provided the following guidance:
"a MI Power Grid order is anticipated to be issued by the end of this yea
which will initiate a workgroup to focus on the creation of appropriate financia
incentives and penalties to address outages and distribution performance
moving forward. Additional guidance on the focus of this workgroup will b
provided at that time." (page 71)
Further, in its November 2022 Order within the Performance Based Ratemakin
section (starting on page 472), the Commission referenced its September 202
Order and provided the following guidance:
"the Commission anticipates providing further guidance on this issue by the
end of the year or soon thereafter." (page 473)
At the time of the filing of the instant case, neither the establishment of the working
group focused on financial incentives nor any other further guidance on this issu
has been communicated by the Commission.
Given this recent Commission guidance, the Company does not think it appropriate
to put forth a broader PBR proposal, potentially including financial incentives an
penalties, in the instant case. The Commission has clearly communicated that
intends to provide additional guidance on this topic, including the commencement

1		of a financial incentives and penalties workgroup. As such, the Company believes
2		it would be premature to put forth a proposal in a contested case before that
3		workgroup has completed its work and the Commission has provided guidance on
4		what it feels is an appropriate path forward.
5		
6		With that said, the Company highlights that it remains open to a broader application
7		of PBR, including the potential use of financial incentives and penalties, based on
8		the findings of the workgroup, industry best practices, and future Commission
9		guidance.
10		
11	Distri	<u>bution IRM – Scope and Surcharge</u>
12	Q17.	What is the timing of the IRM being proposed by the Company?
13	A17.	The Company is proposing to establish a roughly three-year IRM that begins
14		concurrent with the projected test year for the instant case on December 1, 2023.
15		Given that typical distribution planning and reporting activities are completed on a
16		calendar year basis, the Company believes it is most appropriate to align the IRM
17		to calendar years if possible. As such, the Company is proposing that the first year
18		of the IRM extend for 13 months such that it encompasses all of calendar year 2024.
19		Specifically, the proposed IRM "Plan Years" are as follows:
20		• IRM Plan Year 1: December 1, 2023 to December 31, 2024
21		• IRM Plan Year 2: January 1, 2025 to December 31, 2025
22		• IRM Plan Year 3: January 1, 2026 to December 31, 2026
23		
24		Given this timing, the IRM Plan Year 1 surcharges would be established at the same
25		time new rates are implemented subsequent to an order in the instant case. Any

Line <u>No.</u>		U-21297
1		over-recovery due to underinvestment by the Company would be returned to
2		customers as I describe later in my testimony.
3		
4	Q18.	How did the Company determine what capital programs to include in its
5		Distribution IRM proposal?
6	A18.	To determine which capital programs to include in its proposed Distribution IRM,
7		the Company used the following set of screening criteria:
8		• Critical to customer safety, reliability, and/or resiliency. Given the
9		Company's responsibility to deliver safe and reliable power, the Company
10		first looked for capital programs critical to delivering on these objectives.
11		Further, in its November 2022 Order, the Commission specified that it
12		potentially views the conversion of the Company's distribution grid as an
13		appropriate application of an IRM:
14		
15		"As such, the Commission may be willing to consider a long-term
16		investment recovery mechanismto ensure that the spending included in
17		rates for strategic capital improvements - including the ultimate conversion
18		of DTE Electric's distribution grid - is spent for these purposes" (page
19		77, emphasis added)
20		
21		So while the Company broadly looked for programs critical to customer
22		safety, reliability, and/or resiliency, it specifically identified programs
23		supporting the ultimate conversion of the Company's distribution grid.
24		

1 Sufficient size and duration. As discussed previously, the execution of the ٠ 2 IRM will require an increased administrative commitment from the 3 Company and Staff. As such, the Company believes that for the initial 4 application of the IRM, programs should be sufficiently large to justify this 5 increased commitment. Further, programs should be longer-term in nature 6 given that the IRM in effect establishes a sustained and dedicated funding 7 source for specific programs. Programs with diminishing spend or that are 8 short-term in nature are best assessed through the traditional ratemaking 9 process. 10 11 Well-understood scope. The Company believes that the work to be 12 completed within the programs included in the initial iteration of the 13 Distribution IRM should be well-defined and well-understood, such that the 14 Company can establish criteria for how future projects will be selected and 15 Staff and the Commission can have a good sense of the types of projects 16 that will be executed during the IRM timeframe. Having a well-defined 17 scope is also important in ensuring that the selected programs are 18 measurable, such that the Company can report robust program execution

19 20 metrics.

Line

No.

## Q19. Using this screening criteria, what capital programs is the Company proposing to associate with its Distribution IRM?

A19. The Company applied the screening criteria described above to its distribution
capital programs and identified five programs that it proposes to include in the
initial iteration of the Distribution IRM. These capital programs are:

Line <u>No.</u>		U-21297
1		• Circuit Conversions, including both City of Detroit Infrastructure (CODI)
2		and non-CODI conversions. Company Witness Deol further describes this
3		program in his testimony.
4		• Sub-transmission Redesign & Rebuild. Company Witness Deol further
5		describes this program in his testimony.
6		• Breaker Replacement. Company Witness Elliott Andahazy further
7		describes this program in her testimony.
8		• Underground Residential Distribution (URD) Replacement. Company
9		Witness Elliott Andahazy further describes this program in her testimony.
10		• 4.8 kV Circuit Automation. Company Witness Hill further describes this
11		capital program in his testimony.
12		
13	Q20.	What level of investment is the Company proposing for IRM treatment?
14	A20.	Exhibit A-33, Schedule X1 outlines the level of investment that the Company is
15		
1.0		proposing to be authorized for IRM treatment for the distribution capital programs
16		proposing to be authorized for IRM treatment for the distribution capital programs identified above. This information is also summarized in Table 1 below, and further
16 17		proposing to be authorized for IRM treatment for the distribution capital programs identified above. This information is also summarized in Table 1 below, and further supported by Company Witnesses Deol, Elliott Andahazy, and Hill in their
16 17 18		proposing to be authorized for IRM treatment for the distribution capital programs identified above. This information is also summarized in Table 1 below, and further supported by Company Witnesses Deol, Elliott Andahazy, and Hill in their testimonies. While the Company believes it may need to increase annual investment
16 17 18 19		proposing to be authorized for IRM treatment for the distribution capital programs identified above. This information is also summarized in Table 1 below, and further supported by Company Witnesses Deol, Elliott Andahazy, and Hill in their testimonies. While the Company believes it may need to increase annual investment in these programs in the future, the proposal presented in the instant case keeps
16 17 18 19 20		proposing to be authorized for IRM treatment for the distribution capital programs identified above. This information is also summarized in Table 1 below, and further supported by Company Witnesses Deol, Elliott Andahazy, and Hill in their testimonies. While the Company believes it may need to increase annual investment in these programs in the future, the proposal presented in the instant case keeps annual investment levels capped at projected expenditures for the projected test
16 17 18 19 20 21		proposing to be authorized for IRM treatment for the distribution capital programs identified above. This information is also summarized in Table 1 below, and further supported by Company Witnesses Deol, Elliott Andahazy, and Hill in their testimonies. While the Company believes it may need to increase annual investment in these programs in the future, the proposal presented in the instant case keeps annual investment levels capped at projected expenditures for the projected test year ending November 30, 2024.
<ol> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> </ol>		proposing to be authorized for IRM treatment for the distribution capital programs identified above. This information is also summarized in Table 1 below, and further supported by Company Witnesses Deol, Elliott Andahazy, and Hill in their testimonies. While the Company believes it may need to increase annual investment in these programs in the future, the proposal presented in the instant case keeps annual investment levels capped at projected expenditures for the projected test year ending November 30, 2024.
<ol> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>23</li> </ol>		proposing to be authorized for IRM treatment for the distribution capital programs identified above. This information is also summarized in Table 1 below, and further supported by Company Witnesses Deol, Elliott Andahazy, and Hill in their testimonies. While the Company believes it may need to increase annual investment in these programs in the future, the proposal presented in the instant case keeps annual investment levels capped at projected expenditures for the projected test year ending November 30, 2024.

2

3

authorized for IRM treatment starting in IRM Plan Year 1, concurrent with the start of the projected test year in the instant case.

4 For the Conversions and Sub-Transmission Redesign & Rebuild programs, the 5 Company is proposing that only a portion of proposed projected test year program 6 investment be authorized for IRM treatment in IRM Plan Years 1 and 2. The 7 difference in approach for these two programs is due to the nature of the projects 8 that are executed within them. More specifically, projects within these programs 9 tend to be longer-term and extend over multiple calendar years. For the sake of 10 project planning, cost accounting, and ease of understanding, the Company does 11 not think it practical to split a single project into two parts, whereby part of the 12 project is initially recovered through base rates and the remainder is recovered 13 through a separate IRM surcharge. As such, the Company's proposal reflects that 14 any project that has started before the projected test year in the instant case would 15 continue to be addressed through base rates and the typical rate case process. For 16 projects with multiple phases where natural "breakpoints" in the project work exist, 17 the Company proposes utilizing IRM treatment for any phase starting after the 18 projected test year in the instant case has begun. Any new project starting after the 19 projected test year has begun would be authorized for IRM treatment. As a result 20 of this approach, the amount of capital authorized for IRM treatment for these two 21 programs would increase over time as "in flight" projects or project phases are 22 completed and replaced by new projects authorized for IRM treatment. By IRM 23 Plan Year 3, the Company is proposing that the full proposed investment in these 24 programs be authorized for IRM treatment.

25

		Γ	Distribution IRN	1
Capital Program	<b>Projected</b> <b>Test Year</b> (12 mos. end 11/30/24)	Plan Year 1 13 mos. ending 12/31/2024	Plan Year 2 12 mos. ending 12/31/2025	Plan Year 3 12 mos. ending 12/31/2026
Conversions	371.6	1.6	185.8	371.6
Sub-transmission Redesign & Rebuild	107.6	5.5	53.8	107.6
Breaker Replacement	14.0	15.2	14.0	14.0
URD Replacement	15.0	16.3	15.0	15.0
4.8 kV Circuit Automation	24.4	26.4	24.4	24.4
Total IR	RM Investment	65.0	293.0	532.7

*Table 1: Annual investment levels proposed for IRM treatment (\$M)* 

As described previously, IRM Plan Year 1 includes 13 months of investment to align subsequent IRM plan years to calendar years. As such, the investment levels for IRM Plan Year 1 have been scaled up from the projected test year amount to account for this additional month assuming average monthly investment during the projected test year.

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9 Q21. How should projected test year capital be adjusted if the Commission rejects
10 the IRM as proposed?

A21. Since the Company is proposing to establish the IRM during the projected test year
in the instant case, it has removed the proposed IRM capital programs from the

2

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6

calculation of its projected test year capital expenditures and revenue deficiency as sponsored by Witnesses Deol, Elliott Andahazy, Hill, Uzenski and Vangilder. Instead, a separate revenue requirement has been calculated for the IRM, sponsored by Company Witness Vangilder. This approach avoids "double recovery" whereby the same projected test year capital investments are recovered through both base rates and through the IRM surcharge.

7

8 However, if the Commission rejects the IRM as proposed, the Company proposes 9 that the IRM capital programs would be incorporated back into the calculation of 10 its projected test year revenue deficiency. To support this possibility, Company 11 Witnesses Uzenski and Vangilder have prepared alternative projected test year 12 exhibits which assume that the IRM does not exist, and therefore includes the 13 capital associated with the proposed IRM capital programs in the projected test 14 year. The Company requests that if the Commission rejects the IRM as proposed, 15 it will base its order on the alternative projected test year revenue deficiency 16 calculation included within these alternative exhibits.

17

# 18 Q22. How will the Company select specific projects within each capital program 19 during future Distribution IRM plan years?

A22. In their testimony, Company Witness Deol describes how projects will be selected
 during future IRM plan years for the Conversions and Sub-transmission Redesign
 & Rebuild programs, Company Witness Elliott Andahazy describes how projects
 will be selected during future IRM plan years for the Breaker Replacement and
 URD Replacement programs, and Company Witness Hill describes how projects

Line		N. T. FOLEY 11-21297
<u>No.</u>		
1		will be selected during future IRM plan years for the 4.8kV Circuit Automation
2		program.
3		
4	Q23.	Is the Company proposing that it be able to shift investment between capital
5		programs contained within the IRM?
6	A23.	No, the Company is not proposing that it be allowed to shift investment between
7		capital programs associated within the IRM. Said differently, the Company is
8		proposing that each of the capital programs included within the IRM have its own
9		maximum investment level authorized for IRM treatment, as outlined in Exhibit A-
10		33, Schedule X1.
11		
12		If the Company were to invest more in a capital program than the level authorized
13		for that specific program within the IRM, it could seek recovery of the additional
14		investment through base rates in a future general rate case. If the Company were to
15		invest less in a capital program than the level authorized for that specific program,
16		the over-recovery associated with that underinvestment would be returned to
17		customers in the form of a time-bound credit, as described later in my testimony.
18		
19	Q24.	Would the Company support a broader or narrower application of a
20		Distribution IRM in the instant case?
21	A24.	Potentially, yes. While the Company believes that the proposal it is putting forth
22		for the Distribution IRM represents an appropriate initial application of an IRM for
23		its electric utility, it would potentially be supportive of either a broader or narrower
24		application of a Distribution IRM if the Commission deemed it appropriate to do
25		so.

The Company is interested in establishing the IRM mechanism so that it, along with Staff, the Commission, customers, and other stakeholders can begin to (1) realize the benefits described earlier in my testimony, and (2) drive learnings that can improve the effectiveness and usefulness of the IRM over time. As such, the Company would potentially be supportive of modifications to the scope of the IRM as long as the basic mechanism is established as proposed.

8

### 9 Q25. How are the Company's proposed Distribution IRM surcharges determined?

10 A25. At a high level, the IRM surcharges are calculated in a similar way to how base 11 rates are calculated. First, a separate revenue requirement is determined for the IRM 12 capital using the same methods that are used to calculate the Company's overall 13 revenue requirement, including an assumption of when those investments will be 14 put into service. Company Witness Vangilder supports the calculation of the IRM 15 revenue requirement in his testimony. Then, that revenue requirement is allocated 16 to the Company's various customer classes similarly to how the Company's base 17 revenue requirement is allocated. Company Witness Maroun supports the cost-of-18 service treatment for the IRM revenue requirement in his testimony. From there, 19 the IRM Surcharges are calculated in the same manner as the Company's base rates. 20 Company Witness Willis supports the calculation of the IRM surcharges in his 21 testimony.

22

# Q26. Given the proposed level of capital investment authorized for IRM treatment, what is the IRM Surcharge that will be applied to each rate schedule?

A26. In his testimony, Company Witness Willis provides an IRM surcharge tariff which
captures the complete surcharge schedule that would be applied to each of the
Company's rate schedules. Table 2 below outlines the IRM Surcharge for key
customer groups. The increase in the IRM Surcharge from year to year is reflective
of the additional capital that is being invested and placed in service in each IRM
Plan Year.

	Sel	ected IRM Sur	charges
IRM Plan Year	Residential (\$/kWh)	D3 (\$/kWh)	Primary (\$/kW)
1	0.000152	0.000088	0.01137
2	0.001001	0.000582	0.07507
3	0.003094	0.001797	0.23193

Table 2: Distribution IRM Surcharge Schedule for Select Customer Groups

9

8

7

#### 10 Q27. How is the Company proposing to calculate any IRM over-recovery?

11 A27. At the conclusion of each IRM Plan Year, the Company proposes to calculate a 12 revenue requirement for the completed year based on the actual investments made 13 and put into service through the IRM. As discussed previously, the amount of 14 capital that can be recovered for any program through the IRM would not be 15 allowed to exceed the program-specific maximum authorized by the Commission 16 for IRM treatment as proposed in Exhibit A-33, Schedule X1. The Company 17 proposes to compare that actual revenue requirement to the revenue requirement 18 that was calculated in this proceeding, based on expected investment and plant in-19 service, that was used to set the IRM surcharges. Any difference between the

Line No.

		N. T. FOLEY
Line <u>No.</u>		U-21297
1		revenue requirement based on expected investment and plant in-service and the
2		revenue requirement based on actual investment and plant in-service would
3		represent an IRM over-recovery.
4		
5		The calculation of any IRM over-recovery would be included within the IRM
6		Reconciliation process. Company Witness Vangilder includes an illustrative
7		example of this calculation in his testimony.
8		
9	Q28.	Would the size of any over-recovery be impacted by actual sales during the
10		year?
11	A28.	No. The Company is proposing that the calculation of any over-recovery be based
12		on a calculation of revenue requirements which are developed independent of
13		projected or actual sales.
14		
15		Under this method, the Company is exposed to sales forecast risk, consistent with
16		the risk it is subject to for base rates. If sales are less than forecasted, revenues
17		generated from the IRM surcharge would be less than planned, all else being equal.
18		Likewise, if sales are greater than forecasted, revenues generated from the IRM
19		surcharge would be greater than planned, all else being equal. This symmetrical
20		risk is consistent with the risk borne by the Company associated with base rates.
21		
22	Q29.	How is the Company proposing to address any IRM over-recovery?
23	A29.	The Company is proposing that any IRM over-recovery be deferred as a Regulatory
24		Liability until a subsequent rate case. At that point any IRM over-recovery would
25		be returned to customers through a time-bound credit, with short-term interest. The

No. 1 credit would be allocated to the Company's various classes of customers and 2 calculated in the same manner as the IRM surcharges. Company Witness Uzenski 3 further addresses the proposed accounting treatment in her testimony. 4 5 For example, if the Company were to invest and place into service less than the 6 amount authorized for IRM treatment for any program in a given IRM plan year, it 7 would result in an over-recovery. As part of the IRM Reconciliation process 8 described later in my testimony, the Company would calculate the size of that over-9 recovery and record it as a Regulatory Liability. In a subsequent rate case, that over-10 recovery would be returned to customers through a separate time-bound credit with

- 11 short-term interest.
- 12

Line

13 This approach protects the Company's customers in the event of IRM under-14 investment. This approach also allows the Commission and other stakeholders 15 during a subsequent rate case to confirm that the Company's calculation of any 16 IRM over-recovery is consistent with the methodology described in my testimony.

17

## Q30. How would the IRM surcharges be impacted if the Company files a rate case during the roughly three-year IRM timeframe?

A30. The Company proposes that the IRM surcharges proposed in the instant case would cease when new base rates are implemented after an order is issued in the Company's next general rate case. During that rate case, the Company would propose that all capital invested through the IRM mechanism be rolled into the Company's overall rate base with recovery continuing through base rates. The Company may also propose to implement an updated IRM to address recovery of

1 future capital investment. If the Company were to make such a proposal, it would 2 include new proposed IRM surcharges reflecting the proposed investment 3 authorized for IRM treatment. Such a proposal would also provide an opportunity 4 to make modifications to the IRM scope, mechanics, or reporting elements being 5 proposed in the instant case. 6 7 Absent a general rate case, the IRM surcharges would continue indefinitely at the 8 rates established for IRM Plan Year 3. If this were to occur, the Company's 9 customers would continue to be protected from IRM underinvestment through the 10 **IRM Reconciliation Process.** 11 12 Q31. How would IRM cost recovery be impacted if the Company invests more than 13 the amounts authorized for the IRM programs? 14 A31. If the Company chooses to invest and put into service more than the amount 15 authorized for IRM treatment by the Commission for any program, it could seek 16 recovery of those investments in a subsequent rate case but cannot unilaterally 17 increase the IRM surcharges above the levels approved by the Commission when 18 the IRM is established. 19 20 **Distribution IRM – Annual Processes** 21 Q32. Is the Company proposing any additional planning activities associated with 22 the Distribution IRM? 23 A32. Yes. The Company is proposing that a new IRM Planning Process be established 24 associated with the approval of the Distribution IRM. The planning process is based 25 on that used by the DTE Gas IRM and is intended to (1) provide greater

Line <u>No.</u>		<b>N. T. FOLEY</b> U-21297
1		transparency related to the Company's plans for its IRM investments, and (2) solicit
2		feedback from Staff on the Company's plans.
3		
4		Specifically, the Company proposes that no later than two months prior to the start
5		of each IRM Plan Year it submits to Staff an "IRM Investment Plan" for the
6		upcoming year. This timing is consistent with the DTE Gas IRM. At that time Staff
7		would have the opportunity to review the Company's investment plan and raise any
8		questions or concerns that it had before execution of the plan begins.
9		
10		For IRM Plan Year 1 specifically, the Company anticipates receiving a
11		Commission order in the instant case after IRM Plan Year 1 begins. As such, if the
12		IRM were to be approved in the instant case, the Company will endeavor to work
13		as quickly as possible after receiving an order to submit to Staff its IRM Investment
14		Plan for IRM Plan Year 1. With that said, the Company highlights that much of the
15		information that would be provided in the IRM Investment Plan for IRM Plan Year
16		1, such as planned projects and associated cost estimates, are already available in
17		the instant case.
18		
19	Q33.	Would either Staff or Commission approval be necessary for the Company to
20		begin executing its IRM Investment Plan?
21	A33.	No, the Company is not proposing that the IRM Investment Plan would require
22		Staff and/or Commission approval.
23		
24		With that said, the Company appreciates that the long-term utilization and success
25		of the IRM mechanism requires that a transparent and collaborative process be

Line <u>No.</u>		<b>N. T. FOLEY</b> U-21297
1		established such that the benefits described previously in my testimony can be
2		realized. It is the Company's objective to foster such a process underpinned by the
3		IRM Planning Process that I have described here.
4		
5	Q34.	If Staff and/or Commission approval is not required for the IRM Investment
6		Plan, how is the Company held accountable to make investments consistent
7		with the Commission approval of the IRM?
8	A34.	As part of the IRM Planning Process, Staff would have the opportunity to identify
9		areas and/or specific investments where it believes that the Company is potentially
10		deviating from the Commission's approval of the IRM. If any concerns were raised,
11		the Company could then work with Staff to try and address those concerns, and
12		adjust its plans if appropriate, prior to execution of the investment plan.
13		
14		Furthermore, the Commission would have the opportunity to evaluate past IRM
15		investments in subsequent rate cases when the Company proposes to transfer those
16		investments into its overall rate base. In this way, the Company is held accountable
17		to make investments consistent with the Commission approval of the IRM.
18		
19	Q35.	What types of information would be provided in the IRM Investment Plans?
20	A35.	The Company proposes to provide the following information as part of its IRM
21		Investment Plans:
22		• A list and description (e.g., location, scope of work, etc.) of all projects
23		planned for the upcoming year;

Line <u>No.</u>		U-21297
1		• The scoring of planned projects against previously established selection
2		criteria as defined by Company Witnesses Deol, Elliott Andahazy, and Hill
3		in their testimonies for each capital program; and
4		• The estimated level of investment for each of the planned projects,
5		including a projection of investments that will be completed and/or put into
6		service.
7		
8		The information described above would be provided for each capital program
9		authorized for IRM treatment.
10		
11	Q36.	Is the Company proposing any reporting and reconciliation activities
12		associated with the Distribution IRM?
13	A36.	Yes, the Company is proposing that a new IRM Reconciliation Process be
14		established associated with the approval of the Distribution IRM. The intent of the
15		IRM Reconciliation Process is to (1) provide greater transparency into the
16		Company's execution of its IRM Investment Plans, and (2) reconcile actual
17		investment and plant in-service to planned investment and plant in-service such that
18		any over-recovery associated with program underinvestment can be returned to the
19		Company's customers.
20		
21		Specifically, the Company proposes that no later than three months after the end of
22		each IRM Plan Year it submits to Staff an "IRM Execution & Reconciliation
23		Report" for the completed plan year. This timing is consistent with the DTE Gas
24		IRM.
25		

1	Q37.	What types of information would be provided in the IRM Execution &
2		Reconciliation Report?
3	A37.	The Company proposes to provide the following information as part of its IRM
4		Execution & Reconciliation Report:
5		• A list and description (e.g., location, project scope, etc.) of actual project
6		investments during the completed IRM Plan Year, specifically highlighting
7		projects that were completed and/or put into service. This would be
8		compared to the list of planned project investments identified in the IRM
9		Investment Plan, including commentary explaining the causes of any
10		deviations;
11		• A comparison of actual investment amount to planned investment amount
12		(as identified in the IRM Investment Plan) for each project, including
13		commentary explaining the cause of any deviations;
14		• Program execution metrics, which I describe in detail later in my testimony;
15		• Total actual investment compared to total investment authorized for IRM
16		treatment, by program; and
17		• The calculation of any over-recovery based on actual investment and plant
18		in-service, as I have described earlier in my testimony.
19		
20		The information described above would be provided for each capital program
21		associated with the IRM.
22		
23	<u>Distri</u>	<u>bution IRM – Program Execution Metrics</u>
24	Q38.	Is the Company proposing to report any metrics associated with the
25		Distribution IRM?

1	A38.	Yes. As part of the IRM Execution & Reconciliation Report that would be
2		submitted to Staff after the conclusion of each IRM Plan Year, the Company is
3		proposing to begin reporting new program-specific execution metrics. These
4		metrics are designed to help assess the Company's execution of its IRM Investment
5		Plans and are specific to each capital program authorized for IRM treatment.
6		
7		The Company's proposed approach to IRM program execution metrics was
8		modeled after the DTE Gas IRM which provides metrics associated with both work
9		completed and project costs.
10		
11	Q39.	What metrics will be reported for the Conversions program?
12	A39.	The specific program execution metrics that the Company is proposing to report for
13		the Conversion program are:
14		• Overhead (OH) line miles converted vs. target
15		• Average cost per OH line mile converted vs. target
16		• Underground (UG) line miles converted vs. target
17		• Average cost per UG line mile converted vs. target
18		• Higher voltage substations constructed vs. target
19		• Average cost per higher voltage substation constructed vs. target
20		• 4.8 kV substations decommissioned vs. target
21		• Average cost per 4.8 kV substation decommissioned vs. target
22		
23		Company Witness Deol further supports the reporting of these metrics.
24		

1	Q40.	What metrics will be reported for the Sub-transmission Redesign & Rebuild
2		program?
3	A40.	The specific program execution metrics that the Company is proposing to report for
4		the Sub-transmission Redesign & Rebuild program are:
5		• OH line miles rebuilt vs. target
6		• Average cost per OH line mile rebuilt vs. target
7		• UG line miles rebuilt vs. target
8		• Average cost per UG line mile rebuilt vs. target
9		• Stations constructed and/or rebuilt vs. target
10		• Average cost per substation constructed and/or rebuilt vs. target
11		
12		Company Witness Deol further supports the reporting of these metrics.
13		
14	Q41.	What metrics will be reported for the Breaker Replacement program?
15	A41.	The specific program execution metrics that the Company is proposing to report for
16		the Breaker Replacement program are:
17		• Number and type of breakers replaced vs. target
18		• Average cost per breaker (by type) vs. target
19		
20		Company Witness Elliott Andahazy further supports the reporting of these
21		metrics.
22		
23	Q42.	What metrics will be reported for the URD Replacement program?
24	A42.	The specific program execution metrics that the Company is proposing to report for
25		the URD Replacement program are:

Line <u>No.</u>

Line No.		<b>N. T. FOLEY</b> U-21297
1		• Miles of URD replaced vs. target
2		• Average cost per mile of URD replaced vs. target
3		
4		Company Witness Elliott Andahazy further supports the reporting of these
5		metrics.
6		
7	Q43.	What metrics will be reported for the 4.8 kV Circuit Automation program?
8	A43.	The specific program execution metrics that the Company is proposing to report for
9		the 4.8 kV Circuit Automation program are:
10		• Units installed vs. target
11		• Average cost per unit installed vs. target
12		
13		Company Witness Hill further supports the reporting of these metrics.
14		
15	Q44.	Will any program-specific metrics be tied to financial incentives or otherwise
16		impact cost recovery?
17	A44.	No, the Company is not proposing to introduce any financial incentives or penalties
18		to the program execution metrics outlined in this section of my testimony. As
19		discussed previously, the Company is anticipating additional guidance from the
20		Commission on the use of financial incentives, including the commencement of a
21		workgroup focused on that topic.
22		
23	Q45.	Does this complete your direct testimony?
24	A45.	Yes, it does.

### **STATE OF MICHIGAN**

## **BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

In the matter of the Application of	)
DTE ELECTRIC COMPANY	)
for authority to increase its rates, amend	)
its rate schedules and rules governing the	)
distribution and supply of electric energy, and	)
for miscellaneous accounting authority.	)

Case No. U-21297

### QUALIFICATIONS

#### AND

#### DIRECT TESTIMONY

OF

#### SHANNEN M. HARTWICK

#### DTE ELECTRIC COMPANY QUALIFICATIONS AND DIRECT TESTIMONY OF SHANNEN M. HARTWICK

Line <u>No.</u>

<u>NU.</u>		
1	Q1.	What is your name, business address and by whom are you employed?
2	A1.	My name is Shannen M. Hartwick (she/her/hers), Director of Tree Trim, One
3		Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company.
4		
5	Q2.	On whose behalf are you testifying?
6	A2.	I am testifying on behalf of DTE Electric Company (DTE Electric or Company).
7		
8	Q3.	What is your educational background?
9	A3.	I graduated from the University of Michigan with a Bachelor of Science in
10		Engineering in 2007. I am currently in the Executive MBA program with the Ross
11		School of Business at the University of Michigan. I plan to complete this program
12		in April 2023.
13		
14	Q4.	What is your work experience?
15	A4.	I began my career with DTE Electric in 2008 and have been employed there since.
16		I started out as an Associate Engineer in the Performance Management group where
17		I worked on several process improvement projects across Distribution Operations.
18		Over the years, I held a number of positions with increasing leadership
19		responsibilities primarily within Distribution Operations and spent a year in DTE
20		Electric's strategy team. Within Distribution Operations I worked in areas that
21		include: Process Management Team, Substations, Asset Optimization (SOC,
22		Strategy, and dispatch), Southeast Service Operations and Tree Trim.
23		

No. 1 In 2014, I took a position as a Developmental Field Supervisor – Southeast Service 2 Operations where I was responsible for leading the frontline lineman performing 3 maintenance, operations, and construction on DTE Electric's electrical distribution 4 system. 5 6 In 2015, I was promoted to Manager – Tree Trim where I was responsible for 7 leading Operations for the Tree Trim Team, comprised of DTE Energy Employees 8 and all six of our tree trim vendors (comprising over 1300 employees in 2022). In 9 this role, I was responsible for safety, quality, productivity, customer satisfaction, 10 storm and trouble restoration efforts, and relationships with municipalities. 11 12 Q5. What are your current job responsibilities? 13 A5. Currently, I am the Director of Tree Trim. In this role, I am responsible for the 14 strategy and execution of the Tree Trim Program. This includes contract 15 negotiations, strategy, planning, auditing, execution, outage restoration trimming, 16 customer satisfaction, tree trim technology, and scheduling. 17 18 06. Have you previously sponsored testimony before the Michigan Public Service 19 **Commission (MPSC or Commission)?** 20 A6. Yes. I sponsored testimony in Case No. 20836. In addition, I supported the 21 preparation of testimony on the topic of the Company's tree trimming program in

Line

22 previous rate cases (Case Nos. U-20162 and U-20561).

Line <u>No.</u>				<b>S. M. HARTWICK</b> U-21297	
1		Purpose of Testimony			
2	Q7.	What is th	ne purpose of	your testimony?	
3	A7.	As referen	ced in Witness	s Robinson's description of the distribution witnesses, the	
4		purpose of	my testimony	is to:	
5		• Discus	s the importa	nce of and progress made in DTE Electric's vegetation	
6		manag	ement ("Tree	Trimming") program;	
7		• Suppor	rt the Operati	ons and Maintenance (O&M) expenses related to tree	
8		trimmi	ng efforts for t	he historical test period 2021, 2022, and the projected base	
9		O&M	expenses and t	he Tree Trim Regulatory Asset Surge funding amount for	
10		Decem	ber 1, 2023 to	November 30, 2024;	
11		• Reques	st approval of	the Surge Program funding for 2025;	
12		• Provide details related to the Company's Tree Trimming Surge Program that			
13		will deliver on the reliability goals established in the Company's Distributed			
14		Grid Plan (DGP);			
15		• Describe the customer benefits of the Company's expanded Tree Trimming			
16		Surge	Program to dat	te.	
17					
18	Q8.	Are you s	ponsoring any	v exhibits in this proceeding?	
19	A8.	Yes. I am supporting the following exhibits:			
20		Exhibit Schedule Description			
21		A-13	C5.6.1 Projected Tree Trim Expenses		
22		A-22 L1 Projected Value of Tree Trimming Surge Program			
23		A-22 L2 Projected Value of Tree Trim Risk Optimization Mod		Projected Value of Tree Trim Risk Optimization Model	
24		A-31 V1 2021 Tree Trim Annual Report			
25					

Line <u>No.</u>		U-21297
1	Q9.	Were these exhibits prepared by you or under your direction?
2	A9.	Yes, they were.
3		
4	<u>Outlin</u>	ne of Testimony
5	Q10.	How is your testimony organized?
6	A10.	My testimony is organized as follows:
7		Progress of the Company's Tree Trimming Program/Measuring Work Volume
8		Enhanced Tree Trimming Program Results
9		Tree Trimming Surge Program
10		Spot Trimming
11		Funding Required
12		Tree Trimming Surge Funding Mechanism
13		Resourcing the Tree Trimming Surge
14		Program improvements and Looking Beyond the Conclusion of the Surge
15		Herbicide Program
16		Measuring Progress
17		• Conclusion
18		
19	Pro	ogress of the Company's Tree Trimming Program/Measuring Work Volume
20	Q11.	What is the Company's Tree Trimming Program?
21	A11.	The Company has an ongoing Tree Trimming Program to address interference
22		between vegetation and electric distribution facilities. The objectives of the
23		program are to reduce tree-related safety hazards and to reduce the volume of tree-
24		related trouble cases thereby increasing customer reliability. The Company's Tree

Trimming Program, which is based on industry best practices and the Company's 25

Line No		<b>S. M. HARTWICK</b> U-21297
<u>10.</u>		experience, is known as the Enhanced Tree Trimming Program ("ETTP"). The
2		ETTP was described in detail in testimony in the Company's last five rate cases:
3		Case Nos. U-18014, U-18255, U-20162, U-20561, and U-20836.
4		
5	Q12.	Was the MPSC supportive of ETTP in Case No. U-20162?
6	A12.	Yes. The Commission approved the first three years of the Tree Trimming Surge
7		Program as requested by the Company. The Commission indicated that it would
8		reevaluate the remainder of the Surge funding at a future date. In the final order the
9		Commission noted:
10 11 12 13 14 15 16 17 18 19		The Commission reiterates its desire for a safe and reliable electric system as stated on pp. 43-44 of the April 2018 order regarding the ETTP program. The record shows that DTE Electric has continued to bring tree trimming spending into line with the approved amounts, and the Commission agrees that falling behind in this area will cost more in the future and perpetuate reliability challenges. The record also shows direct, quantifiable benefits in terms of reliability improvements resulting from the ETTP program. 3 Tr 200-206. [MPSC Case No. U- 20162, May 2, 2019 Order, p 79
20	Q13.	Has the MPSC continued to support the Surge program?
21	A13.	Yes. The Commission approved an additional year of Surge funding for calendar
22		year 2022 in Case No. U-20561, and in Case No. U-20836 the Commission
23		approved the Surge funding through 2024.
24		
25	Q14.	Does DTE Electric break its territory down into zones for ETTP purposes?
26	A14.	Yes. There are three circuit zones.
27		
28	Q15.	How does the ETTP define tree work to be performed based on circuit zones?

1	A15.	In the right-of-way of all zones, the Company attempts to remove all small trees
2		and larger trees that pose an unacceptable risk to the electrical system.
3		Additionally, the Company attempts to mitigate all hazard trees (trees outside the
4		right of way that are dead, diseased, or dying and threaten to interrupt service to
5		customers).
6		
7		Specifically, in Zone 1, the portion of the circuit from the substation to the first
8		protective device or drop down, the Company removes all branches overhanging
9		the conductors. In Zone 2, the portion of the circuit from the first protective device
10		or drop down to the fused lateral, and Zone 3, the fused laterals, the Company
11		removes all softwood and hardwood branches overhanging the conductors at less
12		than a forty-five-degree angle.
13		
14	Q16.	What were the results of the Tree Trimming Program in 2021?
15	A16.	The 2021 results are described in terms of miles trimmed, units completed, cost to
16		achieve, reliability impact, and customer satisfaction.
17	(	i) Miles Trimmed: The Company trimmed 5,747 line miles on 721 separate
18		circuits, falling short of its plan of 6,156 miles.
19	(	ii) Units Completed: The Company completed 23,784 tree trim comparable units
20		compared to a target of 23,524. I discuss this more later in my testimony.
21	(	iii) Costs to Achieve: DTE Electric spent \$140.2 million on tree trimming line
22		clearance maintenance in 2021.
23	(	iv) Reliability Impact: Circuits trimmed as part of the ETTP since 2015 show an
24	· · · · · · · · · · · · · · · · · · ·	average annual reduction of 71 percent in the number of tree-related customer

#### SMH-6

1		interruptions <sup>1</sup> and an average annual reduction of a	approximately 59 percent in
2		the number of customer minutes of interruptic	$on^2$ in the year following
3		trimming, compared to the non-ETTP circuits. Th	ese results are discussed in
4		more detail later in my testimony and in the Co	mpany's annual Tree Trim
5		Report for 2021, submitted in March 1st, 2022 and	d included as Exhibit A-31
6		Schedule V1.	
7	(	v) Customer Satisfaction: An important measure of	customer satisfaction is the
8		number of MPSC complaints filed each year rela	ated to the Company's tree
9		trimming work. Although the complaints for	tree-related service issues
10		increased slightly to 68 in 2022 compared to 51 for t	the same timeframe in 2021,
11		complaints were primarily driven by customers as	king for tree trimming. The
12		complaints have largely not been driven by custor	mer concerns regarding the
13		tree trimming work conducted on their propertie	s; rather, they demonstrate
14		customers' support for tree trimming and its positiv	ve impacts on reliability and
15		costs.	
16			
17	Q17.	How many miles did the Company anticipate trimm	ning in 2022?
18	A17.	The Company plans to trim 6,300 miles in 2022. This is	is 553 more miles than were
19		trimmed in 2021.	
20		Table 1Tree Trimming	Mileage
21			
22			
23 24			
25			
26			
27			

<sup>&</sup>lt;sup>1, 2</sup> Weighted average of circuits trimmed from 2015 to 2021

#### Line <u>No.</u> 1 2

	Annual Plan Miles Completed / Planned	% of System (miles)	
2021 Actual	5,747	19%	
2022 Plan	6,300	20%	

3

#### 4 Q18. Does the Company expect to achieve the 2022 target?

5 A18. Yes. As of mid-November, we achieved our 6,300 miles target, and trimmed over
6 6,700 miles for the entire year.

7

# 8 Q19. In Case No. U-20836 the Company testified it would trim 7,500 miles in 2022 9 with Surge funding. Can you explain why your plan was adjusted to trim 6,300 10 miles?

11 A19. Yes. The model used in Case No. U-20836 was built on an average mile (average 12 density, average complexity, and therefore average units). When we develop 13 specific plans for each year the Company prioritizes circuits based on reliability 14 and wire down reduction. In response to the severe storms in 2021, the Company 15 identified communities significantly impacted and prioritized trimming those areas 16 prior to the 2022 storm season. These circuits were considered off-cycle and an 17 average cost higher than our system average. Most of these circuits are located in 18 vegetation dense areas with majority backlot work.

- 19
- 20

2

3

## Q20. How many miles have been trimmed to the ETTP standard within the City of Detroit prior to 2022 compared to what is expected to be trimmed by the end of 2022?

4 A20. Prior to 2022, the Company trimmed 2,351 miles to the ETTP standard in the City 5 of Detroit. In 2022, DTE Electric has trimmed 505 miles in Detroit. Results are highlighted in Table 4 below. By the end of 2022, 96% of the City of Detroit line 6 7 miles have been trimmed to the ETTP standard compared to 77% of the overall 8 system.

- 9
- 10

		Trimmed to ETTP Standard through 2021	Trimmed to ETTP Standard at end of 2022				
Annual trimmed ETTP Miles		455	505				
	All ETTP Miles Trimmed <sup>1</sup>	2,351	2,856				
Total Detroit Miles <sup>2</sup> All ETTP Miles Percentage of Detroit Complete <sup>3</sup>		2,500	2,500				
		80%	96%				
	All ETTP Miles Percentage of System Complete	70%	77%				
	<ol> <li>Includes second or third cycle ETTP trim.</li> <li>Includes circuits that cross into or out of Detroit. Detroit only miles are approximately 2400 but miles are counted by circuit, not municipality.</li> <li>Numerator only includes unique miles trimmed to ETTP, therefore does not double count miles on second-cycle or beyond</li> </ol>						
	Enhanced 7	Tree Trimming Program R	<u>esults</u>				
Q21.	21. What methodology was used to calculate the ETTP performance?						
A21.	The Company continues to use the same methodology outlined in Case No. U-						
	20561 as well as in the March 1, 2022 Tree Trim Annual Report submitted in the						
	Case No. U-20162 docket. The March 1, 2022 Tree Trim Annual Report has been						
	<b>Q21.</b> A21.	Annual trimmed ETTP Miles All ETTP Miles Trimmed <sup>1</sup> Total Detroit Miles <sup>2</sup> All ETTP Miles Percentage of Detroit Complete <sup>3</sup> All ETTP Miles Percentage of System Complete (1) Includes second or third cyce (2) Includes circuits that cross in miles are counted by circuit, (3) Numerator only includes un on second-cycle or beyond Enhanced T Q21. What methodology was un A21. The Company continues the 20561 as well as in the Mark Case No. U-20162 docket.	Annual trimmed ETTP       Standard through 2021         Annual trimmed ETTP       455         All ETTP Miles       2,351         Total Detroit Miles <sup>2</sup> 2,500         All ETTP Miles       80%         Complete <sup>3</sup> 80%         All ETTP Miles       70%         Complete <sup>3</sup> 70%         Complete       70%         Omplete       70%         Output       10         Includes second or third cycle ETTP trim.         (2)       Includes circuits that cross into or out of Detroit. Detroit only miles are counted by circuit, not municipality.         (3)       Numerator only includes unique miles trimmed to ETTP, ther on second-cycle or beyond         Enhanced Tree Trimming Program R         Q21.       What methodology was used to calculate the ETTP         A21.       The Company continues to use the same methodolog         20561 as well as in the March 1, 2022 Tree Trim Ann         Case No. U-20162 docket. The				

Table 2

**City of Detroit ETTP Miles** 

1		submitted as Exhibit A31, Schedule V1 for reference. The report, and results
2		mirrored below, include outage and event data through the end of the 2021 calendar
3		year. Final data for 2022 calendar year is not available but will be included in the
4		2022 Annual Report submitted on March 1st, 2023.
5		
6	Q22.	What has been the improvement in outage events on circuits trimmed to the
7		ETTP compared to the non ETTP control group?
8	A22.	The actual difference of outage events on ETTP circuits compared to the balance
9		of the system not trimmed ETTP is 69.1% in post-trim year 1, 65.2% in the second
10		year, 73.50% in the third year, and 63.1% in the fourth year. The actual reduction
11		for Years 1-4 post ETTP trim are depicted in Table 3.

Line No.

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#### Table 3 **ETTP Tree-Related Outage Event Difference Compared to**

	Non ETTP Circuits						
	Number of Dist. Circuits ETTP Trimmed	% Change in Outage Event Reduction for ETTP circuits	% Change in Outage Event Reduction for Non- ETTP circuits	Difference in % Change in Event Reduction ETTP vs Non-ETTP circuits	U-20162 Surge Model Reduction		
1 Year Post Trim	1,389	-29.3	39.8	-69.1%	-57.0%		
2 Years Post Trim	972	-1.0%	64.1%	-65.2%	-57.0%		
3 Years Post Trim	509	2.4%	75.9%	-73.5%	-50.0%		
4 Years Post Trim	180	33.6%	96.7%	-63.1%	-37.0%		

3

#### 4 Q23. How does this reduction compare to results under the prior trimming 5 practice?

As discussed in Case No. U-20162, (3T 202) the past practice of trimming a 6 A23. 7 "clearance circle" around conductors provided only a 13% reduction in tree-related 8 events in the year following trimming as compared to the average number of events 9 in the three-years preceding trimming.

10

#### 11 Q24. Do you see similar differences for customer interruptions and the number of 12 customer minutes of interruption on ETTP vs. non-ETTP circuits?

13 A24. Yes. Using the same methodology discussed above, the Company has determined 14 that actual customer interruptions on ETTP circuits vs. Non-ETTP circuits show a
73.9% difference in Year 1, 66.8% difference in Year 2, 78.9% difference in Year
3, and 52.7% difference in Year 4. These results are shown in Table 4. Customer
minutes of interruption, shown in Table 5, also show significant improvements.
Actual minutes of customer interruption on ETTP circuits vs. Non-ETTP circuits
show a 66.7% difference in Year 1, 56.9% difference in Year 2, 46.3% difference
in Year 3, and 40.8% difference in Year 4.

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Table 4	Post ETTP Tree-Related Customer Interru	ption
		perom

	Number of Dist. Circuits ETTP Trimmed	% Change in Customers Interrupted for ETTP circuits	% Change in Customers Interrupted for Non- ETTP circuits	Difference in % Change in Customers Interrupted ETTP vs. Non-ETTP circuits	U-20162 Surge Model Reduction
1 Year Post Trim	1,389	-45.8%	28.1%	-73.9%	-57.0%
2 Years Post Trim	972	-22.4%	44.3%	-66.8%	-57.0%
3 Years Post Trim	509	-37.4%	41.5%	-78.9%	-50.0%
4 Years Post Trim	180	-7.1%	45.5%	-52.7%	-37.0%

**Difference Compared to Non ETTP Circuits** 

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Table 5

Post ETTP Tree-Related Customer Minutes of Interruption

<b>Difference Compared to Non ETTP Circuits</b>					
	Number of Dist. Circuits ETTP Trimmed	% Change in Customer Minutes Interrupted for ETTP circuits	% Change in Customer Minutes Interrupted for Non- ETTP circuits	Difference in % Change in Customer Minutes Interrupted ETTP vs. Non-ETTP circuits	U-20162 Surge Model Reduction
1 Year Post Trim	1,389	-54.7%	12.0%	-66.7%	-57.0%
2 Years Post Trim	972	-20.9%	35.9%	-56.9%	-57.0%
3 Years Post Trim	509	-52.1%	-5.9%	-46.3%	-50.0%
4 Years Post Trim	180	-39.1%	1.7%	-40.8%	-37.0%

3

4

# 5 Q25. What has been the reduction in wire-down events post-ETTP trimming?

A25. Wire downs on the circuits that have been trimmed as part of the ETTP are
significantly lower in the years after trimming compared to Non-ETTP circuits. The
Year 1 difference is 35.2%, Year 2 is 37.1%, Year 3 is 26.9% and Year 4 is 12.7%.
Reductions are shown in Table 6.

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Table 6

	ETTP Circuits				
	Number of Dist. Circuits ETTP Trimmed	% Change Wire-Down Events for ETTP circuits	% Change for Wire-Down Events for Non-ETTP circuits	Difference in % Change in Wire-Down Events ETTP vs. Non- ETTP circuits	
1 Year After Trimming	1,389	-25.6%	9.6%	-35.2%	
2 Years After Trimming	972	-15.4%	21.7%	-37.1%	
3 Years After Trimming <sup>3</sup>	509	-13.0%	13.9%	-26.9%	
4 Years After Trimming <sup>3</sup>	180	-7.8%	4.9%	-12.7%	

**Post-ETTP Wire-Down Difference Compared to Non-**

3

# 4 Q26. Of the four metrics shown in Tables 3-6, which one best illustrates the impact 5 of the Tree Trimming Program?

A26. Tree-related outage events and wire down reduction are most closely tied to the
effectiveness of the Tree Trimming Program. The Tree Trimming Program has the
capability to reduce events and wire downs by trimming and removing trees that
threaten the distribution system. Tree-related customer outages are also highly
correlated to tree-trim effectiveness but incorporates some degree of randomness
based on where the event occurs on the circuit. If the event is on the backbone of
the circuit, then more customers are likely to be impacted. Because the majority of

<sup>&</sup>lt;sup>3</sup> Sample size is relatively small for 3 & 4 years after trimming

<u>No.</u>		
1		tree related minutes are the result of storms, minutes of customer interruption can
2		be more variable because they are impacted by circumstances outside of the control
3		of the tree-trim program including crew availability, travel time to outage, outage
4		prioritization, and accessibility of outage.
5		
6		Tree Trimming Surge Program
7	Q27.	What is the biggest root cause of outages?
8	A27.	As discussed in the Company's DGP (U-20147), tree interference remains the
9		leading driver of customer outages. Tree-caused outages account for two-thirds of
10		the time that customers spend without power; thus, the successful execution of the
11		Tree Trimming Program will allow the Company to significantly improve the
12		overall reliability of electric service.
13		
14	Q28.	What is the best way to reduce tree-related outages?
15	A28.	A robust Tree Trimming Program is needed to address system reliability including
16		reduction of outage events, customer interruptions, customer minutes of
17		interruption, wire downs, and other non-outage <sup>4</sup> trouble events. The program must
18		be funded to maintain a tree-trim cycle that permits the subsequent trimming of a
19		circuit before the trees on that circuit grow back into the Company's wires and
20		become hazards.
21		
22	Q29.	What is the Company's vision for its Tree Trimming Surge Program?
23	A29.	The Company remains firmly committed to its Tree Trim maintenance program and
24		bringing all circuits on-cycle to the ETTP trimming specification. This will be

<sup>&</sup>lt;sup>4</sup> A non-outage trouble event is an event where a customer is experiencing trouble with their electric service but they still have power (ie wire down, low voltage)

<b>.</b>		S. M. HARTWICK
Line <u>No.</u>		U-21297
1		accomplished by continuing to improve the efficiency with which trimming work
2		is executed and by working through the regulatory process to obtain the funding to
3		support the program.
4		
5	Q30.	When did the Surge Program begin?
6	A30.	The company began the Surge Program in 2019, as a result of the order in Case No.
7		U-20162.
8		
9	Q31.	Is there an expected trimming cycle for the Surge Program?
10	A31.	Yes, while still in the midst of the Surge, the Company is currently working to have
11		all on-cycle circuits trimmed at a 5-year cycle, e.g., if a circuit was trimmed in
12		2017, it was trimmed again in 2022. However, once the Surge is completed, the
13		Company may elect for a risk-based, variable maintenance cycle. This is discussed
14		later in my testimony.
15		
16	Q32.	What is meant by "backlog" and "on-cycle"?
17	A32.	Backlog refers to the circuit miles that have yet to be trimmed as part of the ETTP.
18		On-cycle means that the circuit miles have been trimmed within the last five years
19		to ETTP specification.
20		
21	Q33.	Will the Company prioritize circuits already trimmed as part of the ETTP
22		before the circuits on the backlog?
23	A33.	Yes. Circuits already trimmed as part of the ETTP will be maintained on a five-
24		year cycle, while also addressing the backlog of circuits that have yet to be trimmed
25		as part of the Company's ETTP.

2 How many miles need to be trimmed annually to achieve a five-year cycle? **O34**. 3 A34. Assuming an average mile, DTE Electric currently needs to trim approximately 4 6,538 miles per year to achieve the optimal five-year cycle for distribution circuits. 5 As discussed above, miles vary significantly from year to year, so the Company can 6 be above or below the 6,538 mile mark and still be on target for a five-year cycle. 7 Table 7 lays out the necessary distribution and subtransmission miles that need to 8 be trimmed to maintain the appropriate cycle.

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Table / Tree Trimining Cycle Dength			
	Overhead Miles	Cycle Length (years)	Cycle Mileage (miles / year)
Distribution Circuits	28,459	5	5,692
Subtransmission Circuits	2,539	3	846
Total	30,998	4.75	6,538

Tree-Trimming Cycle Length

11

# 12 Q35. Why is the Company moving to a five-year cycle?

Table 7

A35. The Company typically performs trimming within 15 feet on either side of the
distribution pole centerline, or approximately 10 feet from the conductors. The
Company's target of a five-year cycle is based on the following facts:

- 16 (1) Trees near the Company's distribution equipment grow approximately 10 feet
  17 on average in five years.
- 18 (2) The five-year cycle provides a reasonable and acceptable level of tree-to 19 conductor contact comparable to the industry standard of 10% 15%. Tree-to 20 conductor contact represents the likelihood of any portion of the tree touching the
   21 conductor. A tree-to-conductor contact level of 10% 15% denotes the estimated

		S. M. HARTWICK
Line <u>No.</u>		U-21297
1		average percentage of trees in contact with the overhead electrical facilities across
2		the entire distribution system when the recommended cycle length and clearance
3		standards are reached.
4		
5	Q36.	How does the Company's targeted cycle length compare to the industry
6		benchmarks?
7	A36.	The Company's targeted five-year cycle on distribution circuits is comparable to
8		the actual industry average of 4.9 years, per the report published by CN Utility
9		Consulting, Inc. (CNUC) - Distribution Utility Vegetation Management
10		Benchmark Survey Results 2016 - as shown in Figure 1. Furthermore, all but six
11		of the participating companies target a cycle of five years or less.
12		



V11

W24

Company Code

Z11

6X

X26

V3 X5 X10

X15

N26

V20 Z21

Z5 /21 N14

Y11

X17

N13

3

2

Υ8

Y22 Z13 Z8 X16 Y24 X25 **V12** 

V21

Target 🔜 Actual ----- Average Target - - Average Actual

V4 Z22

#### 4 Q37. Are the specifications applied consistently throughout the Surge?

V19

Y12 V6 Z9 X12

5 A37. Yes. Tree-trimming specifications are applied consistently throughout the 6 Company's service territory. The Company trims and removes trees to maintain 7 circuit clearance for one five-year cycle worth of growth, which, on average, 8 necessitates ten feet of clearance to the outermost conductor. The specification is 9 focused on clearing vegetation within the right-of-way. In addition, while trimming 10 a circuit the Company identifies priority trees outside the right-of-way that could 11 pose a risk and attempts to mitigate. The required clearance is species-specific. All 12 circuits are audited post trimming to ensure the specifications have been meet. Any 13 deviation from specification is corrected by our contractors at no additional cost to 14 the company.

15

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# Q38. Why is a three-year cycle needed on subtransmission circuits?

A38. The three-year cycle is necessary because of the high customer impact of
subtransmission lines. A trouble event on a subtransmission circuit can potentially
cause an entire substation to lose power, which would affect up to 10,000+
customers, while a trouble event on a distribution circuit would affect up to 1,000+
customers. Therefore, outage events on subtransmission lines have significantly
greater impact than a similar outage event on a distribution circuit.

8

# 9 Q39. Have there been changes to the Surge Program?

10 A39. Yes. On August 31, 2021, the Company proposed additional funding for the Tree Trim program in Case no. U-21128. Per the application, the Company would 11 12 increase its investment in the Tree Trim Surge during the remainder of 2021 13 through 2023, beyond the authorized regulatory asset amounts, and will not seek 14 recovery of the additional expenditures. This has the effect of advancing the 15 Company's tree trimming efforts while avoiding future customer expense for those 16 investments, thus providing an affordability benefit to customers. The Company's application was approved on November 4<sup>th</sup>, 2021 and the Company committed to 17 18 \$90 million of incremental funding for the Tree Trimming program.

19

# Q40. How can customers stay informed about Tree Trimming work being performed in their area?

- A40. Customers interested in seeing if Tree Trimming work is being performed in their
   respective area can visit the Company's external website at
- 24 https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=5d9dc2eb1244456
- 25 <u>18959ce788086e00e</u>. These maps were developed in 2022 to inform our customers

# **S. M. HARTWICK** U-21297

of the reliability work the Company is performing on their behalf, and show work completed in the last 6 months and scheduled to be completed within the next 12 months current example of this map can be seen below.

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1	(2)	Few

1 (2) Fewer outage and non-outage events, leading to improved reliability and a 2 positive impact on reactive O&M and capital costs; this will also allow for the 3 re-allocation of resources to other necessary work across the Company's 4 distribution system,

- 5 (3) Fewer customer complaints. The Company recognizes that tree-related outage
  and non-outage events are a concern for our customers that can be rectified
  through the tree-trim program and requested funding,
- 8 (4) Lower future trimming costs as the number of trees growing within the right-9 of-way are trimmed or removed more frequently, resulting in the need to 10 remove less wood from the trees near the Company's lines, and
- 11 (5) Lower customer costs as tree-related outages are reduced (improved reliability
  12 will reduce downtime for customers' manufacturing processes, allow
  13 commercial businesses to remain open, and reduce the inconveniences that
  14 residential customers experience).
- 15

# 16 Q42. Did the Company provide a valuation of the tree trim surge in a previous case?

A42. Yes, in Case No. U-20836 the Company provided a net present value (NPV)
analysis, which was supported by Witness Vangilder, on Exhibit A-22, Schedule
L1 pages 3 and 6. That analysis indicates that the NPV associated with continued
execution of the Surge program is \$71.2 million favorable to customers when
compared to just the baseline O&M tree trimming spend without the Surge funding.
The Company has not updated that analysis but believes that its results are still
valid.

24

1	Q43.	How much does the Company expect to reduce costs per line mile trimmed
2		upon achieving a five-year trimming cycle?
3	A43.	Based on the work study completed by ECI Consulting <sup>5</sup> , the Company expects its
4		cost per line mile to decrease, on average, by 40% compared to the initial trimming
5		conducted as part of the ETTP. This will vary widely based on actual circuit
6		conditions.
7		
8	Q44.	How many tree-related trouble events does the Company expect to reduce
9		upon achieving a five-year cycle through the investment surge?
10	A44.	Based upon details from the Company's outage and dispatch management systems,
11		the Company typically attributes approximately 44,700 outage and non-outage
12		events to trees, or 23% of its roughly 192,300 average annual outage and non-
13		outage events the Company experiences. Upon completion of the Surge, the
14		Company's modeling estimates that the tree-related events will be reduced by
15		approximately 43% as shown in Table 8 below.

16

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 Table 8
 Average Annual Outage and Non-Outage Events

Outage and Non-Outage Events	Pre-Surge 2014-2018 Average	5 Year Cycle Achieved	% Reduction
Tree-Related	44,716	25,379	43.2%

18

# 19 Q45. What reliability improvements will be provided through the Surge program?

 $<sup>^5</sup>$  ECI provides vegetation management consulting, field services, and remote sensing/software consulting services to the utility industry.

Line <u>No.</u>		U-21297
1	A45.	The Company expects a 40% reduction in tree-related All-Weather SAIDI. This
2		reduction is driven by fewer tree-related events.
3		
4	Q46.	How did the Company determine the percentage reduction in events upon
5		completion of the Surge?
6	A46.	The Company based the 40% reduction upon:
7	(	(1) Accounting for weather variability, the circuits trimmed as part of ETTP show
8		a 72% improvement reduction in events in the year after trimming as compared
9		to the three years prior to trimming the circuit; and
10	(	(2) Consultation with ECI indicated a reduction in the cycle length from an
11		effective eight and a half-year cycle to a five-year cycle would reduce events
12		by 35%; and
13	(	(3) Benchmarking of peer utilities suggests an improvement in event reductions in
14		excess of 50%.
15		
16	Q47.	What will reliability performance be if the Surge program is defunded?
17	A47.	The base funding level, absent the Surge, would limit the Company's ability to
18		address backlog miles, which have not been trimmed 8+ years, in a timely manner.
19		Delaying trimming of these miles will lead to an increase in outage and non-outage
20		events, including wire downs, and erode customer satisfaction, thereby increasing
21		complaints to the MPSC. Tree-related reactive and storm costs would also increase,
22		taking away from the funds that were to be allocated to planned investment and
23		maintenance activities for our customers.
24		

Q48. Does it cost more to trim a circuit if it is not trimmed on-cycle? 25

9

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10

Table 9Projected Impact on Cost of Deferring Maintenance

11

Timing of Trimming	Years since last trim	Relative Cost
Optimum	5	\$1
1-year past optimum	6	\$1.16 to \$1.23
2-years past optimum	7	\$1.30 to \$1.43
3-years past optimum	8	\$1.40 to \$1.59
4-years past optimum	9	\$1.47 to \$1.69

12

# 13 Q49. Will it take more resources to trim a circuit if it is not trimmed on-cycle?

A49. Yes. Longer tree trimming intervals result in higher tree trimming cost over time,
as also described in the 1997 ISA study. As illustrated in Figure 2, as the time since
last trim continues to grow, the work becomes more complex as trees begin to
interfere with the conductors.

# DTE ELECTRIC COMPANY QUALIFICATIONS AND DIRECT TESTIMONY OF SHANNEN M. HARTWICK

Line <u>No.</u>		
1		
2	Figure 2	Illustrative Tree Growth Impact on Complexity
3	(Years since Last Trim)	



4		
5		Spot Trimming
6	Q50.	Has the Company increased its reactive tree trim activities above what was
7		originally planned for in the Surge plan?
8	A50.	Yes. Reactive trouble activities in support of outages and wire downs are included
9		in the Surge funding. This includes reactive spot trimming which has increased to
10		address circuits with high volumes of customer reliability issues.
11		

1	Q51.	How does spot trimming differ from ETTP trimming?
2	A51.	Spot trimming is conducted exclusively on poor performing circuits, not yet
3		trimmed to the ETTP specification, that have a high number of sustained and/or
4		momentary outages. Spot trimming involves targeted trimming at select trouble
5		locations to address ongoing emergent issues. ETTP trimming addresses the entire
6		circuit and the full trim specification, as discussed above.
7		
8	Q52.	Why can't the spot trimming work wait until the circuit is scheduled for ETTP
9		trimming?
10	A52.	Some circuits need spot trimming before ETTP trimming can be completed in order
11		to improve reliability for the customer in the meantime. Completing the Surge
12		program to ensure all overhead mils are on the designed cycle will not be completed
13		until 2025.
14		
15	Q53.	What advantages does spot trimming have over ETTP maintenance
16		trimming?
17	A53.	Spot trimming is more agile and, when frequent outage circuits present themselves,
18		allows the Company to address some customer concerns within days to weeks from
19		the time they first arose.
20		
21	Q54.	How much spot trimming work was performed in 2020 and 2021?
22	A54.	Spot trimming was conducted at approximately 12,300 pole locations in 2020, and
23		nearly 13,000 poles in 2021. To put these numbers in context, the electrical system
24		has approximately one million DTE owned pole locations.
25		

Line <u>No.</u>

1	Q55.	Were funds for spot tree trimming included in the Surge modeling in Case No.
2		U-20162, U-20561 or U-20836?
3	A55.	Yes. They were included as part of "Reactive Maintenance Costs" in Exhibit A-22,
4		Schedule L1, Line 4 on pages 1 and 2. However, the projected cost has increased
5		as the number of pole locations in need of spot trimming has increased.
6		
7	Q56.	Why has the amount of spend for spot trimming increased?
8	A56.	While the number of circuits not trimmed to the ETTP specification has diminished
9		over the years, the circuits remaining in backlog continue to experience poor
10		reliability. Increasing spot trimming allows us to provide an immediate resolution
11		for the worst performing circuits. Summer of 2021, with the severe storms,
12		highlighted the need for additional spot trimming due to significant weather events
13		and high volume of storms. Recognizing the need for additional spot trimming, a
14		portion of the \$90M incremental tree trim surge has been allocated to that program.
15		
16	Q57.	How does the Company choose which circuits receive spot trimming?
17	A57.	Circuits that are not in the tree trim maintenance plan, or scheduled for other capital
18		improvement plans, in the current year (and future 12 months) and have had four
19		or more sustained outages and/or nine or more momentary outages in a rolling
20		twelve-month period are reviewed to determine if spot tree trimming is needed.
21		Circuits are then selected and prioritized based on an index that accounts for the
22		concentration on the circuit of the number of customers affected, tree trim schedule,
23		SAIFI (System Average Interruption Frequency Index), and MAIFI (Momentary
24		Average Interruption Frequency Index). This selection process has enabled DTE to

Line <u>No.</u>								U-21297
1		address a number of the Company's high risk, in terms of service quality, customers						
2		who had p	oor reliabili	ity.				
3								
4	Q58.	Do you ex	xpect the ne	ed for spot	tree trimm	ing to be re	duced as the	e backlog of
5		non-ETT	P circuits a	re reduced:	?			
6	A58.	Yes. Spot tree trimming is an effective "bridge" for circuits that are outside of the						
7		tree trim c	ycle. We e	xpect the sp	ot tree trim p	program to b	e reduced to	a minimum
8		once the S	Surge is con	nplete and th	ne system or	n a 5-year cy	vele. Table 1	0 shows the
9		spot trimn	ning budget	declining in	the final ye	ears of the Su	irge.	
10								
11		Т	able 10	Non-Inflat	ion Adjuste	ed Spot Trin	n Budget 20	19-2024
12				I	I	1		
		Year	2019 A	2020A	2021A	2022	2023	2024
		Budget	\$5.2M	\$8.3M	\$8.0M	\$10.0M	\$5.0M	\$0.5M
13								
14	Q59.	Have you	updated <b>E</b>	Exhibit A-22	2, Schedule	L1, pages 1	and 2 to in	nclude 2021
15		funding f	or spot trin	nming expe	ense and the	e associated	spot trimm	ing savings
16		as the bac	cklog is red	uced?				
17	A59.	No. The s	spot trimmi	ng expenses	and saving	s can be ref	erenced in (	Case No. U-
18		20836 Ex	hibit A-22,	Schedule L1	, lines 4 an	d 16. The C	ompany has	not updated
19		the Exhibit	it, but the va	lues are still	l valid.			
20								
21	Q60.	Can spot	trimming r	eplace ETT	TP?			
22	1.0	N. C.			£ 1.1:		1 . 1	6

A60. No. Spot trimming is not capable of delivering the clearance needed for an entire 22 circuit in order to achieve a 5-year cycle. 23

Line <u>No.</u>						S.	M. HARTW U-2	/ <b>ICK</b> 1297
1				г г т				
2				Funding F	<u>kequirea</u>			
3	Q61.	How much <b>l</b>	base tree tri	mming has t	he company	requested in	1 prior cases	, and
4		the instant c	ase?					
5	A61.	In Case No.	U-20561, the	e tree trimmi	ng program v	vas funded to	• \$97.9 millio	on fo
6		base tree trin	n spending. Ii	n Case No. U	-20836, the C	Company requ	uested \$103.9	)M in
7		base funding	to catch bac	k up due to 1	not filing a ra	te case in sev	veral years. In	n thi
8		instant case,	the Company	is requesting	g \$106.4M fo	r 2024 to con	tinue to follo	w the
9 10		original O&N	M funding lai	id out in U-20	0561 (Table 1	11)		
11	ſ		Table	11 Base	Tree Trim C	&M in U-20	)561	I
		Year	2021	2022	2023	2024	2025	
		O&M (\$M)	99.1	101.5	103.9	106.4	109.0	
12								
13	Q62.	Did the Con	1pany reque	st Surge Fu	nding for 202	23 and 2024	in U-20836?	
14	A62.	Yes. The Cor	mpany reque	sted \$67.0 m	illion in 2023	and \$52.7 m	nillion for 202	24, as
15		outlined in th	e previous ra	te cases. The	Commission	's Order on N	lovember 18,	2022
16		approved the	e Company's	requested d	eferral fundi	ng and treatr	nent for 2023	3 and
17		2024 (p. 263	).					
18								
19	Q63.	Does the Co	mpany fores	see needing (	the Surge fu	nding in 202	5?	
20	A63.	Yes. Consist	ent with wha	it was propos	ed in Case N	los. U-20162	and U-2056	1, the
21		Company for	resees needin	g the Surge f	funding of \$4	3.7M for 202	5. In Case N	[o. U
22		20836, the C	Company wa	s targeting to	o complete th	ne Surge a y	ear early wit	h the
23		incremental	\$90M; howe	ever, due to	revised cost	projections	, the Compa	ny i
24		committed to	o complete th	e Surge in 20	)25.			
				SMH	-30			

Line No.

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2

# Q64. Can you please describe Exhibit A-13, Schedule C5.6.1?

3 A64. This page shows the calculation supporting Tree Trimming expenses for the 4 projected test period. The annual amounts approved by the Commission in Case 5 No. U-20561 are broken down into two categories: tree trim O&M – Base Level 6 (Line 5) and Tree Trim Regulatory Asset – Surge Funding (Line 1). Lines 7 through 7 9 calculate the projected period O&M amount for the base plan. Line 7 shows the 8 approved O&M Base Level amount of \$106.19 million for 2024. Lines 8 and 9 9 show the historical O&M and adjustment needed to align with the approved base 10 O&M from Case No. U-20561. The \$2.609 million adjustment in line 9, column (f) 11 is simply the difference between the historical amount and the approved amount. 12 This adjustment is made to ensure the projected period reflects the amount 13 approved in U-20561 instead of 2022 actual plus inflation.

14

15

#### **Tree Trimming Surge Funding Mechanism**

#### 16 Q65. Can you please describe Exhibit A-22, Schedule L1, pages 1 and 2?

17 These pages show the details of the calculation supporting the Projected Value of A65. 18 the Tree Trimming Program through 2042. The page is broken up into four sections: Surge Program O&M Costs, Status Quo Program O&M Costs, Surge 19 20 Program Capital Costs, and Status Quo Program Capital Costs. The first section 21 depicts the tree-related O&M costs for the Surge Program. Line (2) depicts the cost 22 to trim the miles needed to achieve a five-year cycle. Line (3) shows the cost of 23 the continuation of the Herbicide Program and is equal to Line (15) as the Herbicide 24 Program. Lines (4), (8), and (9) depict the Tree Trim Reactive Maintenance, Tree 25 Trim Storm, and Other DO Tree-Related O&M Costs, respectively. These costs

1 are dependent upon the projected event reduction resulting from the Surge in 2 investment in the Tree Trim Program. Line (6) conveys the Credit to the Regulatory 3 Asset. This is calculated by taking the Total Tree Trimming O&M Spend in Line 4 (5) and subtracting Line (17), which is the inflation adjusted tree trimming spend 5 for the Status Quo Program. Line (7) conveys the Credit to the Tree Trim 6 Incremental Surge. This is calculated by taking the Total Tree Trimming O&M 7 Spend in Line (5) and subtracting Line (17), which is the inflation adjusted tree 8 trimming spend for the Status Quo Program and Line (7) which is the Credit to the 9 Regulatory Asset.

10

11 The next section demonstrates the tree-related O&M costs for the Status Quo 12 Program, which simply grows at the rate of inflation for Line (17). Lines (16), (19), 13 and (20) are impacted by the Company's ability to maintain limited overhead circuit 14 miles on a five-year cycle. Because an inflation adjusted program does not provide 15 adequate funding to achieve a five-year cycle on the entire system, the reactive, 16 storm, and trouble costs escalate. Line (22) calculates the respective O&M savings 17 of the Surge program as compared to the Status Quo. The third section conveys the 18 Surge program capital costs. The costs shown in Lines (24), (25), and (26) are 19 driven by events and the respective reduction in events expected upon investing in 20 the tree trimming Surge. The fourth section represents the Status Quo Program 21 capital costs. Line (29) conveys the amount of tree trimming charges when 22 trimming in support of replacing an asset on a Blue Sky day, while Line (30) is for 23 Storm spend only. Line (31) depicts the capital spent by the Regional Customer 24 Operations organization as a result of tree-related events. Ultimately, the capital 25 savings from investing in the tree trimming Surge program is shown on Line (33).

Line		<b>S. M. HARTWICK</b> U-21297
<u>110.</u>		
2	<b>O</b> 66.	What is the total forecasted cost of tree trimming from 2022 through 2025?
3	A66.	Tree trimming costs are expected to be approximately \$723.1 million from 2022
4		through 2025, Exhibit A-22, Schedule L1, page 1, line 5, columns d-g.
5		
6	Q67.	How is the base rate cost recovery calculated?
7	A67.	The total amount requested for the projected test period ending on December 31,
8		2024 is \$106.4 million. It is the base O&M assumed in the Case No. U-20561 plus
9		inflation to the year 2024. The inflation rate is detailed on Company Witness Ms.
10		Uzenski's Exhibit A-13, Schedule C5.15.
11		
12	Q68.	How much of the cost will be recovered through base rates?
13	A68.	\$332.6 million is expected to be recovered through base rates from 2023 to 2025
14		Exhibit A-22, Schedule L1, page 1, line 8, columns e-g.
15		
16	Q69.	How much cost is the Company expecting to recover outside of base rates?
17	A69.	The Company is proposing to defer Surge costs up to \$163.4 million above base
18		rates from 2023 through 2025 Exhibit A-22, Schedule L1, page 1, line 12, columns
19		e-g.
20		
21	Q70.	How does the Company expect to recover the program costs above base rates?
22	A70.	The Commission approved regulatory asset treatment for the incremental costs
23		through 2024 totaling \$365.8 million, \$156.9 million of which were securitized in
24		March 2022 pursuant to the Commission's June 23, 2021 order in Case No. U-

Line		S. M. HARTWICK U-21297
<u>No.</u>		
1		21015. Witness Lepczyk discusses how the Company proposes to recover future
2		Surge costs until they can be securitized.
3		
4	Q71.	Why is the Company proposing to securitize the costs?
5	A71.	As previously discussed, the Surge investment is intended to lower future reactive
6		costs that would be incurred given the current state of vegetation near or on the
7		distribution system. Securitization funding recognizes the long-term nature of the
8		program. As the costs are incurred up front and the full savings will not be realized
9		until after the program has matured, recovery over a longer period provides a better
10		matching of costs with the anticipated savings, minimizing the cost impact to
11		customers.
12		
13		Resourcing the Tree Trimming Surge
15		Resourcing the free frimming ourge
13	Q72.	How many resources does the Company need to meet the accelerated Surge
13 14 15	Q72.	How many resources does the Company need to meet the accelerated Surge goals?
13 14 15 16	<b>Q72.</b> A72.	How many resources does the Company need to meet the accelerated Surge goals? To complete the Surge by the end of 2025, the Company estimates needing an
13 14 15 16 17	<b>Q72.</b> A72.	How many resources does the Company need to meet the accelerated Surge goals? To complete the Surge by the end of 2025, the Company estimates needing an average of 1,300 trimmers annually
14 15 16 17 18	<b>Q72.</b> A72.	How many resources does the Company need to meet the accelerated Surge goals? To complete the Surge by the end of 2025, the Company estimates needing an average of 1,300 trimmers annually
14 15 16 17 18 19	Q72. A72. Q73.	How many resources does the Company need to meet the accelerated Surge goals? To complete the Surge by the end of 2025, the Company estimates needing an average of 1,300 trimmers annually Do you expect to maintain a stable number of trimmers on property
14 15 16 17 18 19 20	Q72. A72. Q73.	How many resources does the Company need to meet the accelerated Surge goals? To complete the Surge by the end of 2025, the Company estimates needing an average of 1,300 trimmers annually Do you expect to maintain a stable number of trimmers on property throughout the year?
14 15 16 17 18 19 20 21	Q72. A72. Q73. A73.	How many resources does the Company need to meet the accelerated Surge goals? To complete the Surge by the end of 2025, the Company estimates needing an average of 1,300 trimmers annually Do you expect to maintain a stable number of trimmers on property throughout the year? For 2023, the Company expects to employ an average of 1,300 tree trimmers, in
13 14 15 16 17 18 19 20 21 22	Q72. A72. Q73. A73.	How many resources does the Company need to meet the accelerated Surge goals? To complete the Surge by the end of 2025, the Company estimates needing an average of 1,300 trimmers annually Do you expect to maintain a stable number of trimmers on property throughout the year? For 2023, the Company expects to employ an average of 1,300 tree trimmers, in practice there will likely be resource swings related to seasonality, market crew
13 14 15 16 17 18 19 20 21 22 23	Q72. A72. Q73. A73.	How many resources does the Company need to meet the accelerated Surge goals? To complete the Surge by the end of 2025, the Company estimates needing an average of 1,300 trimmers annually Do you expect to maintain a stable number of trimmers on property throughout the year? For 2023, the Company expects to employ an average of 1,300 tree trimmers, in practice there will likely be resource swings related to seasonality, market crew availability, and natural rotation of outsource crews back to their home areas.
13 14 15 16 17 18 19 20 21 20 21 22 23 24	Q72. A72. Q73. A73.	<ul> <li>How many resources does the Company need to meet the accelerated Surge goals?</li> <li>To complete the Surge by the end of 2025, the Company estimates needing an average of 1,300 trimmers annually</li> <li>Do you expect to maintain a stable number of trimmers on property throughout the year?</li> <li>For 2023, the Company expects to employ an average of 1,300 tree trimmers, in practice there will likely be resource swings related to seasonality, market crew availability, and natural rotation of outsource crews back to their home areas.</li> </ul>

1	A74.	The Company will use a mix of local and non-local crews to conduct the work. The
2		Company will not be able to achieve the plan through the utilization of local
3		trimmers only and will need to continue to utilize qualified tree-trimming crews
4		from outside of our service territory. The long-term plan is to grow the local
5		workforce to achieve an adequate level of qualified local workers and create jobs
6		in Michigan.
7		
8	Q75.	What's the difference between a local tree trimmer and a non-local trimmer?
9	A75.	A local trimmer lives within reasonable driving distance of the DTE Electric service
10		territory and makes union wages. Non-local trimmers normally work in other parts
11		of the country but have come to work for DTE Electric contractors on a temporary
12		basis. A non-local trimmer makes union wages but also requires a daily per diem
13		rate to cover room and board. These requirements make non-local trimmers more
14		expensive than local trimmers.
15		
16	Q76.	What is the Company's plan to create additional local tree trimmers?
17	A76.	The Company has several pathways and initiatives in place or in progress to grow
18		the local workforce:
19	(	(1) The Company has partnered with the City of Detroit, IBEW Local 17, and its
20		tree-trimming contractors to develop and implement a pre-woodsman training
21		pilot program to satisfy the demand for qualified tree trimmers. The pilot tree
22		trimming academy is located within the City of Detroit and facilitates training
23		that is aimed at preparing local resident candidates to work as woodsmen. Once
24		candidates complete the pre-woodsman program, graduates enter the nine-day
25		boot camp that was previously designed in partnership with the Company,

1 IBEW Local 17, and the Company's tree-trimming contractors. The boot camp 2 gives participants intensive training and hands-on work experience on subjects 3 such as safety, climbing systems, climbing techniques, arborist equipment, arborist tools, commercial vehicle operation, tree species identification, 4 5 communication with line crews, customer relations, and aerial rescue 6 techniques. Boot camp graduates enter the Line Clearance Tree Trimming 7 Apprentice Program. The 5,000-hour apprenticeship program, which includes 8 160 hours of classroom training, is recognized by the Department of Labor as 9 an approved apprenticeship program and, as one of two programs in the United 10 States, is benchmarked throughout the industry. The first cohort completed the 11 tree trimming academy in the spring of 2021, and as of December 2022, 148 12 individuals have graduated from the program, with 100% of them being offered 13 a job upon graduation.

14 The Company has implemented a tree-trimming training program in the (2)15 Vocational Village at Parnall Correctional Facility in Jackson. The training 16 program was developed to allow returning citizens to directly enter the 17 apprenticeship program upon leaving the correctional facility. In selecting 18 applicants, the Vocational Village administration heavily weighs the 19 applicant's county of residence to decrease the distance they would have to 20 commute to work once they are released. The Vocational Village was paused 21 for all of 2020 and most of 2021 due to the COVID pandemic. The Vocational 22 Village and training returned in late 2021. The Company has paired 23 graduates 23 with jobs and the tree trimming program continues to be one of the most popular 24 programs in the Vocational Village.

1	(	3) The Company is working with our local contractors to have them continue to
2		hire new trimmers through their normal processes. Typically, this method of
3		hiring has primarily been used to replace attrition but, due to the increase in
4		future work volume, we are requesting that they train additional staff
5		augmentation outside of DTE led activities.
6		
7	Q77.	What other efforts is the Company undertaking to recruit local talent?
8	A77.	The Company is partnering with Local 17 and its contractors to reach out to local
9		high schools, career fairs, and local nonprofit organizations to introduce the tree-
10		trimming trade to interested candidates.
11		
12	<u>]</u>	Program Improvements and Looking Beyond the Conclusion of the Surge
13	Q78.	What improvements or enhancements has the Company made for the Tree
14		Trim program in 2021/2022?
15	A78.	In monitoring best practices and emerging advancements in data analytics within
16		vegetation management, the Company identified LiDAR as an emerging best
17		practice within vegetation management programs. Beginning in 2021 the Company
18		self-funded an extensive investment in LiDAR collection and processing for the
19		entire electrical territory.
20		The Company had previously self-funded smaller scale LiDAR collections to better
21		understand the benefit and potential uses cases for the data. Collecting data for the
22		entire territory would allow the Company to expand those benefits to a larger scale.
23		
~ 1	0.50	What is LiDAD and why is it hanaficial to the Tree Trimming program?

Line	
No.	

16	Q80.	Has the Company already leveraged the LiDAR data?
15		
14		reliability hot spots to emerge.
13		costs for maintenance work, and identity areas where tree encroachment may cause
12		to the Tree Trimming program in the form of assisting in scoping and estimating
11		patterns and emerging reliability hot spots. This data can provide significant value
10		LiDAR technology provides advanced data on the Company's tree density, growth
9		
8		most utilities, especially for their distribution systems <sup>6</sup> .
7		becoming a best practice, adoption of the technology is still preliminary amongst
6		to the system. The investment for this type of data is significant and while it is
5		tool for vegetation management programs to digitalize their assets and assess risk
4		between objects and the ground. In recent years, LiDAR has emerged as a valuable
3		enables the use to develop a 3D image of an area with accurate measurements
2		distance to Earth of different objects, such as trees and utility equipment. LiDAR
1	A79.	LiDAR (Light detection and ranging) is a remote sensing method that measures the

17 A80. Yes. The Company has leveraged the LiDAR data as part of the 2023 pricing 18 negotiations with our tree trim contractors. We provided heat maps showing 19 vegetation presence and encroachment distances to vendors participating in the 20 request for proposal (RFP) for the 2023 maintenance plan. These maps provided 21 additional information for vendors to use in ensuring that they provided competitive 22 bids. The Company also developed a cost model for select substations using the 23 LiDAR data as an input to predict expected cost. This model provided additional 24 data for the Company to reference while in negotiations with tree trimming vendors.

<sup>&</sup>lt;sup>6</sup> The use of LiDAR for transmission systems is more common

Line		<b>S. M. HARTWICK</b> U-21297
<u>No.</u>		
1		
2	Q81.	Does the Company foresee future opportunities to continue to use the LiDAR
3		data?
4	A81.	Yes. The Company is currently developing a risk-based, variable cycle model that
5		will leverage the LiDAR data to help identify optimal trim cycles and emerging hot
6		spots. This model would help elevate the Company's maintenance trimming cycle
7		to be more targeted than the current 5-year standard.
8		
9	Q82.	Why is the Company exploring a risk-based, variable cycle at this time?
10	A82.	As the Company enters the final years of the Surge, the Company recognizes a
11		standard 5-year cycle may no longer be optimum for the system once everything is
12		trimmed to the same specification and considered on-cycle. The Company believes
13		adjusting cycle-lengths based on species growth rates, risk of outages, and cost of
14		trimming will further improve trimming efficiencies and provide reliability benefits
15		to customers. With the acquisition of LiDAR combined with tree species data <sup>7</sup> the
16		Company has acquired over the course of the Surge program DTE Electric has the
17		necessary information to make data-driven improvements to the program.
18		
19		Furthermore, the idea of variable cycles was raised by intervenors and the
20		Commission in the prior rate case, Case No. U-20836. In Case U-20836 (p.487),
21		the Commission ordered the Company to continue to explore efficiency
22		improvements, and benefits from a variable cycle for the tree trimming program
23		and the Company is complying with that directive.

<sup>&</sup>lt;sup>7</sup> Tree species data is important to understand growth rates, wood strength, and susceptibility to disease; these insights enable the Company to better predict when a tree may encroach into our equipment or risk failing (e.g., branch breaking and falling on equipment)

Line No.

1

1

# 2 Q83. How is a risk-based cycle different from a 5-year cycle?

A83. A fixed-year cycle (i.e., 5-year cycle) was the industry standard until recently. The
emergence of remote sensing and advanced data analytics for vegetation programs
allows for companies to begin considering variable cycles.

6

7 Moving towards a variable, risk-based cycle would be a refinement to the 8 Company's maintenance trimming program. The 5-year cycle is based on the 9 average growth rates and tree densities across the entire system and their expected 10 average spatial relation to the conductor. There are areas across the territory with 11 higher tree densities and faster growing species that grow back into the wires prior 12 to 5-years. Conversely there are areas with slower growing species that could go 13 longer between maintenance trims before interfering with the conductor. Moving 14 towards a risk-based cycle would move higher risk areas to a shorter-cycle, and 15 lower risk areas to a longer-cycle, instead of uniformly trimming every area on a 5-16 year cycle.

17

# 18 **Q84.** Are there steps that were necessary prior to considering a risk-based cycle?

- A84. Yes. The Company identified three key steps in the tree trim program that arenecessary in order to consider risk-based cycles.
- (1) The Company needs all circuit miles to be trimmed to the same specification
  and considered on-cycle. It is necessary to complete this step so that all
  circuit miles are on the same baseline, and adjustments to cycle length can
  be made by evaluating of the entire system.

Line <u>No.</u>		U-21297		
1		(2) For the most effective risk-based cycle, the Company plans to use remote		
2		sensing data (e.g., LiDAR) and species data that has been collected over the		
3		past 5 years. Prior to having this robust dataset, the Company lacked the		
4		information necessary to make insightful adjustments to cycle lengths.		
5		(3) To determine the best cycles for each area, the Company needs a model that		
6		leverages the data discussed above to identify the optimum annual plan and		
7		cycle lengths throughout the Company's service territory.		
8				
9	Q85.	Is there an option to stop the Surge and just move to a risk-based cycle?		
10	A85.	No. The Company must get the entire system trimmed to the ETTP specification		
11		prior to moving towards variable, risk-based cycles. Once the entire system is		
12		trimmed to the enhanced specification the Company can move towards a risk-based		
13		cycle.		
14				
15	Q86.	Do other utilities use a risk-based cycle?		
16	A86.	Yes. Based on benchmarking the Company has identified other utilities in the		
17		industry exploring or introducing variable, risk-based variable cycles.		
18				
19	Q87.	What does the Company foresee as the benefit from this shift?		
20	A87.	The Company expects that moving towards a risk-based cycle will result in		
21		trimming efficiencies and improved reliability for high-risk areas. Based on the		
22		benchmarking of other utilities, the Company anticipates the need to trim high-risk		
23		areas more frequently, and low-risk areas less frequently, resulting in an overall		
24		more efficient use of resources. In addition, more frequent trimming in high-risk		

areas should provide reliability benefits to customers, without sacrificing reliability in low-risk areas.

To best understand the benefits, and potential tradeoffs, from a variable, risk-based 4 5 cycle, the Company intends to pilot risk-based cycles in several areas prior to fully 6 moving to this type of maintenance cadence. This will allow the Company to 7 measure the potential benefits of risk-based cycles such as improved trimming 8 efficiencies, lower trimming costs and improved reliability to understand the 9 magnitude of the benefit. In addition, the Company will be able to identify potential 10 challenges and develop countermeasures. For example, if we are trimming in an 11 area more frequently, we may need to address customers concerns with our 12 increased presence on their property. Exact timing, location, and size of the pilot 13 will be determined once the risk-based model is completed at the end of Q1 2023.

14

Line

No.

1

2

3

#### 15 Q88. Is there potential savings from moving to a risk-based cycle?

A88. Yes. Based on industry experts, other utilities have seen a 5% annual cost reduction
 related to maintenance specific trimming activities by optimizing resources and
 annual maintenance plan. The Company believes it is reasonable to assume similar
 savings would be expected, as shown in Exhibit A-22 L2 Line 5.

20

### 21 Q89. How does the Company plan to determine a risk-based cycle?

A89. The Company is developing a sophisticated risk prioritization model that leverages
 remote sensing data (e.g., LiDAR), advanced analytics, and machine learning to
 estimate the probability of vegetation-driven failures and determine optimal trim
 cycles for an area.

Line <u>No.</u>		S. M. HARTWICK U-21297
1		
2	Q90.	What is the forecasted investment for the risk prioritization model?
3	A90.	The direct capital investment for this model is approximately \$6.3 million. In
4		addition, the Company's Digital Infrastructure and Services team supported the
5		development of the model. The capital investment for this effort is \$8.3 million and
6		is discussed in further detail in Witness Sharma's testimony on Digital
7		Infrastructure and Services.
8		
9	Q91.	Is the company seeking recovery for this investment?
10	A91.	Yes. The Company is seeking recovery for this investment as shown in Exhibit A-
11		12, Schedule B5.4, Page 12, line 8 <sup>8</sup> (\$6.3 million). (Related plant activity is
12		included on page 19, line 157, described in more detail by Company Witness
13		Miller.)
14		
15	Q92.	Has the Company calculated the NPV for this investment?
16	A92.	Yes, the NPV for the risk prioritization model is \$11.2 million. Details are included
17		in Exhibit A-22 L2. The expected savings of a risk-based cycle yield a positive
18		benefit for customers.
19		
20	Q93.	What are the next steps regarding the risk prioritization model?
21	A93.	The Company is currently building and operationalizing the risk prioritization
22		model with the anticipated completion of April 2023. Once the model is complete
23		the Company plans to execute a pilot. Beyond the pilot the Company will develop
24		a long-term strategy to maintain and refresh the model.

 $<sup>^8</sup>$  The Company inadvertently omitted \$4.88M of costs in 2022 from the model. This error was identified shortly before filing and the Company was unable to update the model.

		S. M. HARTWICK
Line <u>No.</u>		U-21297
1		
2	Q94.	Are there other elements of the model?
3	A94.	Yes. Beyond identifying optimum trim cycles for different areas, the model will
4		provide key improvements to the Company's process for annual negotiations with
5		tree trimming vendors.
6		(1) This model will expand and enhance the cost modeling the Company has
7		already done using LiDAR data. This model would provide expected costs
8		for the entire territory which will assist in future negotiations.
9		(2) The model will have a visual component, which will enable the team to
10		streamline development of maps for bidding and community
11		communication purposes.
12		(3) The model will improve the process for developing the annual plan by
13		balancing work across the system based on the available tree trimming
14		resources in each area.
15		
16		Herbicide Program
17	Q95.	What is the herbicide program?
18	A95.	The Company uses EPA-regulated herbicides to replace mechanical removal of
19		vegetation from the right-of-way with a chemical treatment, which will only control
20		the tree species with the potential to grow into electrical wires. The Company has
21		created the program using industry best practices that were collected and developed
22		through benchmarking and by working with an outside consultant - ECI. The
23		Company uses herbicides that include foliar herbicide treatment, basal herbicide
24		treatment, and dormant stem treatment.
25		

Line <u>No.</u>		S. M. HARTWICK U-21297
1	Q96.	How much did the herbicide program cost in 2021?
2	A96.	The Company spent \$1.3 million in 2021.
3		
4	Q97.	How much did the Company spend on the herbicide program in 2022?
5	A97.	The Company spent \$1.5 million as shown in Exhibit A-22 L1 line 3.
6		
7	Q98.	What are the benefits of the herbicide program?
8	A98.	The herbicide treatment will reduce the future cost of maintenance trimming in the
9		right-of-way by reducing tree density. There are other advantages besides realizing
10		cost savings. As tree density and brush height decreases, the electrical system
11		becomes more reliable and the right-of-way becomes more accessible.
12		
13	Q99.	Are there any additional benefits to treating the right-of-way with herbicides?
14	A99.	Yes. Treating the right of ways increases accessibility for our overhead crews,
15		making it safer and easier to access areas in the event of downed wires or broken
16		equipment. Also, because grasses and shrubs are not affected by the herbicide
17		treatment, the area will become a habitat for pollinators, birds, and small mammals.
18		The treatment will also target invasive plant species, limiting their spread.
19		
20		Measuring Progress
21	Q100.	How will the Company evaluate the results of the Tree Trimming Surge?
22	A100.	In compliance with the Commission's Order in Case Nos. U-20162 and U-20561,
23		the Company will provide an annual report detailing circuit performance on March
24		1 <sup>st</sup> until the Surge program is complete.
25		

I	Line
_	_

Ν	0.		

1	Q101. Ho	w will circuit performance be measured in this annual report?
2	A101. Per	the Commission's direction, the Company will provide details on ETTP and
3	sur	ge miles broken out by geographical region and will include:
4	(1)	All activity, costs, and miles trimmed under any and all tree-trimming
5		programs (including 4.8kV Hardening) in the city of Detroit;
6	(2)	Miles completed by service center annually;
7	(3)	Total ETTP Miles completed by service center;
8	(4)	Miles of backlog yet to be trimmed under the ETTP by service center and the
9		total percentage of backlog work remaining;
10	(5)	Average tree density by service center;
11	(6)	Percentage of work that requires climbing to the extent that DTE has reliable
12		data;
13	(7)	Performance of ETTP circuits compared to non-ETTP circuits;
14	(8)	ETTP costs (both capital and O&M);
15	(9)	Number of employees and contractors directly involved in ETTP;
16	(10)	Tree-related outage reductions;
17	(11)	Tree-related SAIDI reductions;
18	(12)	ETTP circuit performance comparing average outages for the three years prior
19		to the enhanced trimming with outages in the years after the trimming has
20		been performed; and
21	(13)	A description of spot-trimming work done on the 10 worst performing
22		circuits.
23		
24		Conclusion
25	Q102. Do	you recommend this continued investment in the tree-trimming program?

1 A102. Yes. The tree-trimming program is the most impactful and important program in 2 the Company's long-term investment strategy for its electric distribution and 3 subtransmission systems. The program has shown that it significantly decreases 4 system risk (specifically reduced wire downs), increases reliability (fewer and 5 shorter outages), and will decrease reactive trouble costs. The tree trimming 6 program as proposed is required to provide safe, reliable and affordable electricity 7 to the Company's customers. Without continuing the Surge investment, the 8 distribution system will continue to degrade, resulting in higher risks and lower 9 reliability. I believe this program is right for our customers and I appreciate the 10 Commission's continued support for the program in Case No. U-20836. The 11 Company is requesting approval of 2025 Surge funding including continued 12 regulatory asset treatment of the Surge costs in order to execute the program in a 13 way that makes it affordable for customers. In addition, the Company is requesting 14 recover of the capital investment for the Tree Trim Risk Prioritization Model to 15 further improve efficiencies of the program beyond the Surge. 16

# 17 Q103. In your opinion are these expenses reasonable and prudent?

A103. Yes, they are. I base my opinion on analysis of past expenses, and the projected
 requirements for labor and materials to conduct the necessary tree trimming.

20

Line

No.

# 21 Q104. Does this complete your direct testimony?

- 22 A104. Yes, it does.
- 23
## **STATE OF MICHIGAN**

## **BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

In the matter of the Application of	)
DTE ELECTRIC COMPANY	)
for authority to increase its rates, amend	)
its rate schedules and rules governing the	)
distribution and supply of electric energy, and	)
for miscellaneous accounting authority.	)

Case No. U-21297

## QUALIFICATIONS

## AND

## DIRECT TESTIMONY

OF

## MICHAEL J. HATSIOS

## DTE ELECTRIC COMPANY QUALIFICATIONS AND DIRECT TESTIMONY OF MICHAEL J. HATSIOS

Line <u>No.</u>

1	Q1.	What is your name, business address and by whom are you employed?
2	A1.	My name is Michael J. Hatsios (he/him/his), and my business address is One
3		Energy Plaza, Detroit, Michigan, 48226. I am employed as Director - Customer
4		Service Operations by DTE Energy Corporate Services, LLC, a subsidiary of DTE
5		Energy.
6		
7	Q2.	On whose behalf are you testifying?
8	A2.	I am testifying on behalf of DTE Electric Company (DTE Electric, DTE or
9		Company).
10		
11	Q3.	What is your educational background?
12	A3.	I earned a bachelor's degree in Mechanical Engineering from Lawrence
13		Technological University in Southfield, MI, and a master's degree in Business
14		Administration from the University of Michigan's Ross School of Business, Ann
15		Arbor.
16		
17	Q4.	What work experience do you have?
18	A4.	Prior to joining DTE, I was employed in various roles as a design and
19		manufacturing engineer for Ford Motor Company and Visteon Automotive. I
20		joined DTE in 2001, and since then I have held positions of increasing
21		responsibility in our non-regulated subsidiaries, Treasury, the Controller's Office,
22		Fossil Generation, Enterprise Performance Management (EPM), and Customer
23		Service.
24		

## 25 Q5. What are your current duties and responsibilities?

Line

No.

## 1 Part 1. Purpose of Testimony

## 2 Q7. What is the purpose of your testimony?

3 A7. The purpose of my testimony is to support the reasonableness and prudency of a 4 subset of the capital projects in the Company's Customer IT Portfolio. Specifically, 5 my testimony will support those projects that are intended to save customers 6 money, that will enhance the manner in which we interact and provide information 7 to customers, that will allow the Company to better serve its most vulnerable 8 customers, and that will expand opportunities for customers to reduce their energy 9 usage and voluntarily participate in the expansion of the Company's renewable 10 energy portfolio.

11

This subset of projects totals \$185.9 million in capital investment, and includes
\$29.5 million for the 12-month historical period ending December 31, 2021, \$103.7
million for the 24-month bridge period ending November 30, 2023, and \$52.7
million for the 12-month projected test period ending November 30, 2024.

16

17My testimony will also provide the details for an additional \$10.8 million in capital18not included in the Customer IT Portfolio, but that is related to the Company's Error19Free Communication (EFC) – Outage Status initiative, for which I am providing20testimony in the instant case. This brings the total capital for which I am providing21testimony in the instant case to \$196.7 million.

22

I will complete my testimony with a discussion of the variance of actual 2021
capital spend, compared to the 2021 capital spend included in the rate base in MPSC
Case No. U-20836.

1 2 **Q8**. How do the capital projects in your testimony align with the Company's 3 priorities? 4 A8. The Company is committed to providing reliable, safe, and affordable utility service 5 to its customers, and to do so while promoting energy waste reduction, expanding 6 its renewable energy portfolio, and reducing its carbon footprint. DTE's Customer 7 Service organization is aligned with and supports these priorities, and is committed 8 to cost effectively providing customers engaging and satisfying transactional (e.g., 9 orders) and non-transactional (e.g., inquiries) interactions across its service 10 channels, to creating programs, rate products, and tools that help customers monitor and reduce their energy usage and lower their monthly bills, and to designing 11 12 renewable energy products that provide equitable opportunities for customers to 13 voluntarily support the Company's clean energy initiatives. 14 15 To that end, the \$196.7 million in capital projects, for which I am providing 16 testimony, are intended to deliver the following outcomes: 17 18 1. Reduced Call Volumes – Lower the volume of live calls to the DTE Contact 19 Center, which will significantly reduce Contact Center O&M expense. 20 2. Increased Operational Efficiencies – Create efficiencies across the Customer 21 Service operating groups to reduce the cost of operations.

22 3. Enhanced Customer Interactions – Improve the effectiveness and quality
23 with which the Company interacts and communicates with customers.

Line <u>No.</u>				U-21297		
1		4. Refor	rmed Collection	n Experiences – Reform the experience for customers		
2		who	struggle to pay	their bills, with the goal of reducing customer arrears		
3		and r	nitigating the ri	sk of customers being shutoff for nonpayment.		
4		5. Expa	nded Energy V	Vaste Reduction (EWR) and Clean Energy Products -		
5		Provide customers with tools, programs, and rate products that help them				
6		reduc	ce their energy u	usage, lower their monthly bills, and reduce their carbon		
7		footp	orint.			
8						
9	Q9.	Are you sp	onsoring any e	xhibits in this proceeding?		
10	A9.	Yes. I am sp	ponsoring the fo	ollowing exhibits:		
11						
12		<u>Exhibit</u>	<u>Schedule</u>	Description		
13		A-12	B5.7.3	IT Customer Service Capital Expenditures		
14				(Strategic, Enhancements, and Compliance)		
15		A-13	C5.9.2	ACPP and TOD Regulatory Asset Deferrals		
16		A-24	N1	Customer Service IT Business Cases - Executive		
17				Summaries		
18		A-24	N2	Historical Spend Variance Summary		
19		A-24	N3	Customer IT Capital Investments with Additional		
20				Project Details		
21		A-24	N5	Call Volume Reduction Savings Summary		
22		A-24	N6	NPV Model for Digital Self-Service Capital Projects		
23		A-24	N7	2021-2022 MIMO Web Self-Service Enhancements		
24		A-24	N8	2021-2022 Outage Web Self-Service Enhancements		
25		A-24	N9	Operational Efficiency Savings Summary		

<b>.</b> .				M. J. HATSIOS		
Line <u>No.</u>				U-21297		
1		A-24	N10	Error Free Communication (EFC) Capital Spend		
2		A-24	N11	PrePay Pilot Objective Utility Pilot Criteria		
3		A-24	N12	PrePay Pilot Customer Personas		
4		A-24	N13	PrePay Pilot Terms & Conditions		
5		A-24	N14	PrePay Pilot Frequently Asked Questions (FAQs)		
6		A-24	N15	PrePay Pilot Enrollment Process		
7		A-24	N16	PrePay Pilot Account Management & Notifications		
8		A-24	N17	PrePay Pilot Disconnect/Reconnect Process		
9		A-24	N18	PrePay Customer Focus Group Results		
10		A-24	N19	PrePay Consumer Survey Data		
11						
12	Q10.	Were tl	hese exhibits pre	epared by you or under your direction?		
13	A10.	Yes, th	ey were. I co-sp	ponsor Exhibit A-24, Schedules N1, N2, and N3 with		
14		Compar	ny Witness Panka	ij Sharma (Witness Sharma). I also co-sponsor Exhibit A-		
15		13, Sch	edule C5.9.2 with	n Company Witnesses Peterson and Sparks.		
16						
17	Q11.	What in	nformation is pr	ovided in the Exhibits?		
18	A11.	Below i	is a summary of 1	the information provided in each of the exhibits that I am		
19		sponsor	ing and co-spons	oring in the instant case:		
20						
21		1. E	Exhibit A-12, Sch	nedule B5.7.3 includes the historical and projected capital		
22		for the IT investments in the Customer IT Portfolio, for which I will be				
23		providing testimony.				
24		2. Exhibit A-13, Schedule C5.9.2, which I am co-sponsoring with Witnesses				
25		F	Peterson and Spa	rks, summarizes the regulatory asset deferrals for costs		

Line <u>No.</u>		U-21297
1		related to the Advanced Customer Pricing Pilot (ACPP) and Time-of-Day
2		(TOD) projects, with the IT portion of the deferred costs included on lines 2
3		and 9 of the exhibit.
4	3.	Exhibit A-24, Schedules N1, N2, and N3, which I am co-sponsoring with
5		Witness Sharma, provides the business case executive summaries (N1), a
6		summary of the recovery request for historical 2021 spend (N2), and
7		additional project details (N3) for 2022 through 2024 projects in all the DTE
8		IT investment portfolios, including the subset of Customer IT Portfolio
9		projects for which I am providing testimony.
10	4.	Exhibit A-24, Schedule N5 provides a summary of the Company's actual
11		(2021/2022) and forecasted (2023-2027) call volumes and O&M savings
12		enabled by its capital project investments in the instant case.
13	5.	Exhibit A-24, Schedule N6 is an analysis of the net present value (NPV) of
14		the savings to customers from the Company's 2021-2024 digital self-service
15		investments.
16	6.	Exhibits A-24, Schedules N7 and N8, provide screenshots of the MIMO and
17		Outage Web enhancements enabled by the Company's 2021/2022 digital
18		self-service investments.
19	7.	Exhibit A-24, Schedule N9, provides a summary of the Operational
20		Efficiency O&M savings forecasted to be achieved by the Company's
21		capital project investments in the instant case.
22	8.	Exhibit A-24, Schedule N10, provides a line-item summary of the
23		Company's capital investments in the Company's Error Free
24		Communications (EFC) – Outage Status initiative.

Line <u>No.</u>		M. J. HATSIOS U-21297
1		9. Exhibit A-24, Schedule N11 through N19, provide additional details, as
2		referenced in my testimony, related to the Company's proposed PrePay
3		Pilot.
4		
5	Q12.	How is your testimony organized?
6	A12.	My testimony consists of eleven parts:
7		
8		• Part 1 – Purpose of Testimony
9		• Part 2 – Customer IT Portfolio Overview
10		• Part 3 – Witness Hatsios Sponsored Projects - Overview
11		• Part 4 – Projects that Reduce Call Volumes
12		• Part 5 – Projects Creating Operational Efficiencies
13		• Part 6 – Projects that Enhance Customer Interactions
14		• Part 7 – Projects that Reform Collection Experiences
15		• Part 8 – EWR & Clean Energy Projects
16		• Part 9 – Regulatory and Compliance Projects
17		• Part 10 – Voluntary PrePay Pilot
18		• Part 11 – Historical 2021 Project Spend Variance
19		
20	<u>Part 2</u>	2. Customer IT Portfolio Overview
21	Q13.	How do the projects in the Customer IT Portfolio align with the overall IT
22		plan for the Company?
23	A13.	The Customer IT Portfolio is a subset of DTE's IT Investment Portfolio and has
24		been developed in parallel with the DTE IT 5-year plan (2021-2025) filed in case
25		docket U-20561. A view of the structure of the DTE IT Investment Portfolio, the

associated categories of investment, and the responsible witness in the instant case
 is provided in Figure 1.

3 4

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Figure 1 DTE IT Investment Portfolios



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6 Consistent with the other IT Investment Portfolios, the projects in the Customer IT 7 Portfolio have been categorized into five areas of targeted investment – 8 Regulatory/Compliance, Sustainment, Return to Health, IT Enhancements, and 9 Strategic (Figure 2). These categories of investment are defined and described in 10 more detail in the DTE IT 5-year plan, and in Witness Sharma's testimony in the 11 instant case.

#### Figure 2DTE IT Investment Categories

Non-Discretionary	Regulatory/ Compliance	Required spend due to regulatory requirements
	Sustainment	Required spend to `run' the organization (e.g., basic internal labor, base operating and system maintenance costs)
	Return-to- Health	Required investments to update systems that are in critical health or have reached end of life
Discretionary	IT Enhancements	Discretionary capacity/capability performance upgrades to core platforms (e.g., SAP, IT) determined by business needs which are not required for `keeping the lights on'
	Strategic	Strategic spend to unlock a new business capability that can realize value for the organization (e.g., customer satisfaction, increased revenue to offset rate increases, etc.)

2

#### 3 Q14. Which categories of investment are addressed in your testimony?

A14. As highlighted in Figure 1, my testimony will include those projects in the
Regulatory/Compliance, IT Enhancements, and Strategic investment categories.
As noted in Figure 2, these projects relate directly to those non-discretionary and
discretionary projects that either are required by mandate or compliance rules
(Regulatory/Compliance), or directly target improving the customer experience,
reducing operational costs, and the effectiveness with which we serve customers
(IT Enhancements, Strategic).

11

12 Not included in my testimony are those Customer IT Portfolio projects that are 13 included in the Sustainment and Return-to-Health investment categories. Like all 14 IT capital assets, hardware and software, customer systems require regular 15 maintenance, and are subject to regular updates and replacement cycles to maintain 16 operational efficiencies and to ensure the seamless and uninterrupted delivery of 17 service. In the instant case, the Sustainment and Return-to-Health projects in the

1

Line No		<b>M. J. HATSIOS</b> U-21297
<u>INO.</u>		
1		Customer IT Portfolio are included in Exhibit A-12, Schedule B5.7.2, and
2		discussed in Witness Sharma's testimony.
3		
4	Q15.	What customer systems are included in scope of work that is funded by the
5		capital projects in the Customer IT Portfolio?
6	A15.	The Customer Technology Platform is made up of three types of systems – Systems
7		of Engagement, Record, and Intelligence - whose components work together, and
8		with other supporting systems, to manage all of the data, business processes, and
9		financial processes required to effectively and efficiently manage customer
10		interactions across the various service channels (Figure 3).



#### Figure 3 Customer Technology Platform

2

3

4

#### To summarize what is included in Figure 3:

 Systems of Engagement – Includes all of the Company's served (Contact Center) and digital self-service channels (IVR, Web, Mobile App, Kiosk)
 customers use to interact with the Company, as well as all of the systems that survey, monitor, and measure the customer experience in those channels. Also included, are those systems that validate and protect customer identities, those that track and monitor the status of customer service orders – i.e., "Where is my Order" (WISMO) – those that manage outbound customer communications, and

Line No.

Line <u>No.</u>	M. J. HATSIOS U-21297
1	the Application Program Interfaces (APIs) required to present data for
2	consumption in the service channels.
3	
4	2. Systems of Record – Consists of two core components, the industry specific SAP
5	Industry Solution for Utilities (SAP-ISU) and the SAP Customer Relationship
6	& Management (CRM) systems, which together are referred to as the
7	Company's Customer Relationship & Billing (CR&B) system. CR&B contains
8	all of the data, logic, and integrations – i.e., the Platform Integration Layer, and
9	SAP Integration Bus – with other Company systems that are needed to manage
10	customer interactions.
11	
12	3. Systems of Intelligence – Stores all of the customer and operational data for
13	consumption by the CR&B system, and for use by the Company's data analytics
14	platform to provide insights into operational performance, business processes,
15	and the customer experience.
16	
17	The capital projects in the Customer IT Portfolio provide the capital resources
18	required to maintain and enhance the different systems within the Customer
19	Technology Platform. This includes all the Sustainment and Return-to-Health
20	projects in Witness Sharma's testimony, which provide funding to ensure the
21	availability and resiliency of the customer systems, and the
22	Regulatory/Compliance, IT Enhancement, and Strategic projects in my testimony,
23	which provide funding to enhance the customers systems to create new system
24	functionality and capabilities that benefit customers, or to comply with any
25	regulatory mandates and industry standards required to serve customers.

Line <u>No.</u>		M. J. HATSIOS U-21297
1		
2	Q16.	How are capital projects identified for inclusion in, and prioritized within, the
3		Customer IT Portfolio?
4	A16.	All Company IT investments must be assessed against one another and prioritized
5		across the DTE IT investment portfolios described in Figure 1. Not all projects
6		brought forward for inclusion can be funded and executed in a given year. As such,
7		project demand significantly exceeds the Company's capacity to fund and manage
8		the projects. To prioritize IT projects, the Company is using a standardized scoring
9		and ranking methodology that assesses investments across its IT portfolios,
10		including the subset of projects in the Customer IT Portfolio for which I am
11		providing testimony in the instant case. This Project Prioritization Scoring (PPS)
12		model is described in more detail in Witness Sharma's testimony in the instant case.
13		
14	<u>Part 3</u>	8. Witness Hatsios Sponsored Projects – Overview
15	Q17.	Have you provided summaries of each of the projects in the Customer IT
16		Portfolio for which you are providing testimony?
17	A17.	Yes. The \$185.9 million subset of capital projects in the Customer IT Portfolio are
18		summarized in Exhibit A-12, Schedule B5.7.3 which I am sponsoring as part of my
19		testimony in the instant case. This exhibit includes the list of projects, the project
20		categories, the historical, bridge, and test period capital for each project, and a
21		reference to the associated project business cases.
22		
23		Additionally, Exhibit A-24, Schedules N1 and N3, provide project business case
24		executive summaries (N1) and additional project details (N3) which further
25		describe the scope and costs of each project.

Line <u>No.</u>		M. J. HATSIOS U-21297
1		
2	Q18.	How will you organize and discuss the capital projects you are sponsoring in
3		your testimony?
4	A18.	My testimony in the instant case will align the total \$196.7 million in capital
5		projects, for which I am providing testimony, with the five project outcomes
6		described in Part 1 of my testimony.
7		
8		Table 1 provides an overview of the total historical, bridge, and test period capital
9		that is being allocated to five "portfolios" (i.e., groups) of capital projects. Each of
10		these project portfolios is aligned with one of the five outcomes; with each
11		providing the capital resources required to modify the systems in the Customer
12		Technology Platform to enable the functionality and capabilities required to
13		achieve the outcomes with which each portfolio of projects is aligned.
14		
15		Table 1 also includes \$18.7 million in capital projects that do not directly align with
16		the five identified outcomes, but that are included in the total \$196.7 million in
17		capital projects for which I am providing testimony.
18		
19		
20		
21		
22		
23		
24		
25		

Line <u>No.</u>

> 1 2

## Table 1Witness Hatsios Capital Spend Overview

	Capital (\$000s)			
Expected Project Outcomes	Historical Period	Bridge Period	Test Period	Total
Reduced Call Volumes	12,008	26,919	12,405	51,332
Increased Operational Efficiencies	2,255	17,162	10,732	30,149
Enhanced Customer Interactions	4,765	28,490	12,805	46,060
Reformed Collection Experiences	994	2,191	2,531	5,716
EWR & Clean Energy Products	4,090	31,949	8,691	44,730
Total - Aligned with Expected Outcomes	24,112	106,711	47,164	177,987
Regulatory/Compliance Projects	714	5,325	2,937	8,976
Pre-Pay	6,704	-		6,704
Pre-Pay Phase II			2,640	2,640
Projects less than \$250,000	399	-	-	399
Total - Witness Hatsios Sponsored Capital	31,929	112,036	52,741	196,706

3

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9

As reflected in Table 1, a total of almost \$178.0 million in historical, bridge, and test period capital, is allocated to the portfolio of projects that directly align with the five identified outcomes. Table 1 also includes the previously identified \$18.7 million in total capital that is allocated to projects that do not directly align with the desired outcomes, but that are part of the subset of Customer IT Portfolio projects for which I am providing testimony, which includes:

10

111. Regulatory/Compliance – \$9.0 million in capital projects that are required to12fulfill a regulatory requirement or compliance rule.

Pre-Pay and Pre-Pay Phase II – \$9.3 million in capital for the Company's
 proposed voluntary prepaid billing pilot program.

Line <u>No.</u>	<b>M. J. HATSIOS</b> U-21297
1	3. Projects less than \$250,000 – \$0.4 million in capital for small projects that
2	are each less than \$250,000 in capital.
3	
4	My testimony in the instant case is organized around each of the five identified
5	outcomes, and will be presented as follows:
6	
7	• Part 4 – Projects that Reduce Call Volumes
8	• Part 5 – Projects that Create Operational Efficiencies
9	• Part 6 – Projects that Enhance Customer Interactions
10	• Part 7 – Projects that Reform Collection Experiences
11	• Part 8 – EWR & Clean Energy Projects
12	
13	Each of these five parts of my testimony will discuss the scope of the associated
14	portfolio of projects, the expected outcomes enabled by the implementation of these
15	projects, and the forecasted benefits to DTE customers.
16	
17	Please note that with the exception of those projects that align with "Expanded
18	EWR and Clean Energy Products", and the Pre-Pay/Pre-Pay Phase II projects, the
19	projects in Table 1 are shared assets with costs and benefits that are shared by DTE
20	Electric and DTE Gas customers. As such, my testimony, the supporting data, and
21	the associated outcomes for these projects, unless otherwise noted in my testimony,
22	are inclusive of both DTE Electric and DTE Gas customers.
23	
24	Part 4. Projects that Reduce Call Volumes
25	Q19. What is included in this section of your testimony?

Line <u>No.</u>

1

## A19. This section of my testimony includes an overview of:

2		
3		1. The current state of the volume and types of calls handled in the Contact
4		Center by the Company's internal and external (i.e., vendor) Customer
5		Representatives (CRs).
6		2. The current state of the Company's digital self-service customer solutions.
7		3. The comparison of the Company's handled call volumes, and the maturity
8		of its digital self-service offerings, relative to utility peer companies.
9		4. The scope and impacts of the \$51.3 million in historical (\$12.0 million),
10		bridge (\$26.9 million), and test (\$12.4 million) period portfolio of capital
11		projects (Table 1) that enable "Reduced Call Volumes".
12		
13	Q20.	What is the Company's motivation to reduce the volume of calls handled by
14		CRs in its Contact Center?
15	A20.	The cost of Contact Center operations represents the largest portion of the total
16		Customer Service (CS) Operating & Maintenance (O&M) expense, as shown in
17		Figure 4, which reflects the percent of the total CS O&M expense incurred by each
18		of the CS operating groups during the 2021 historical period - as provided in
19		Witness Sparks' Exhibit A-13, Schedule C5.7, Line 5, Column G.
20		

Line <u>No.</u>

1



As reflected in Figure 4, the Contact Center, in the 2021 historical period, contributed over 50% of the total CS O&M expense, with the most significant driver of Contact Center costs being the handling of live phone calls by CRs. In fact, each incremental call handled by a CR in the Contact Center costs the Company \$11.34, which reflects the 2022 weighted average cost of the Company's internal and external CR resources, and includes overhead costs (e.g. benefits, payroll taxes, etc.) for the internal DTE CRs.

10

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11 With over four million calls handled by DTE CRs in 2022, the transition of 12 customers from this high cost CR channel, to a much lower cost digital self-service 13 channel – IVR, Web, Mobile App, Kiosk – has the potential to significantly reduce 14 Contact Center costs, and to pass those savings on to customers through the utility 15 ratemaking process. An additional benefit to customers is that with a lower volume 16 of calls, the Company can more effectively manage a smaller CR DTE and vendor 17 workforce, which will help ensure performance levels in the Contact Center (e.g., 18 abandon rates, wait times) are consistently maintained.

Line		M. J. HATSIOS U-21297
<u>110.</u> 1		
2	021	What is the current state of the volume and types of calls handled by CRs in
2	Q21.	the DTE Contest Contor?
5	1	
4	A21.	The Company has identified the categories of call types that make up the majority
5		of its transactional and non-transactional (inquiries) interactions with customers,
6		which I've summarized below, and which I will collectively refer to in my
7		testimony as the Company's "five key transactions".
8		
9		1. Collection - Calls from customers who received a shutoff notice, or have
10		been disconnected for nonpayment, and are contacting the Company to
11		discuss the options available to them to avoid shutoff or to restore service.
12		Many of these calls are from the Company's most vulnerable low income
13		customers, who are calling about available energy assistance and to discuss
14		payment plan options.
15		2. Billing – Calls from customers who want to verify their account balance,
16		have questions about their bill, or who want to enroll in one of the
17		Company's billing programs (e.g., Budget Wise Billing, ebill).
18		3. Move-In/Move-Out (MIMO) - Calls from existing and new customers
19		requesting to Start Service at a new location, to Stop Service at an existing
20		location, to Transfer Service between locations, or to inquiry about, or
21		change, an existing MIMO service order.
22		4. Payments – Calls from customers who want to pay their monthly bill, or to
23		check on the status of a recent payment.
24		5. Outage - Calls from customers who are reporting an electric outage, or
25		checking on the status of a reported electric outage.





6

7 As reflected in Figure 5, Contact Center CRs handled 4.23 million calls from 8 customers, of which 3.42 million (81%) were categorized into one of the five key 9 transactions, while the remaining 19% of calls are classified as "Other". This is 10 because until recently, the Company lacked the Speech Analytics capability 11 necessary to automatically identify the reason for a customer's call, relying instead 12 on interaction records to capture those calls for which a system order was created 13 (e.g., payment made, start service order created), and on the CRs to manually 14 capture the reason for calls for which no system order was created. The "Other" 15 bucket represents those calls that were not categorized by the system or the CR into 16 one of the five key transactions. Speech Analytics, which I will discuss in Part 5 of my testimony along with the other projects that enable "Increased Operational 17

Line <u>No.</u>		M. J. HATSIOS U-21297
1		Efficiencies", will automate the process and improve the accuracy with which calls
2		are categorized.
3		
4	Q22.	How does the volume of the Company's live calls compare to its utility peers?
5	A22.	The most recent First Quartile Consulting utility benchmark study, in which the
6		Company participated, indicates that DTE is in the 4th quartile of the utility peer
7		group with regard to the volume of live calls it handles per customer (Figure 6).
8		
9		Figure 6 2022 Utility Peer Call Volume Benchmarks <sup>1</sup>



 2022 First Quartile Benchmarking Study (2021 data). Benchmarking participation confidentiality agreement prevents companies from sharing other company names and results externally

10

# Q23. How have the peer Companies represented in Figure 6 achieved upper quartile volumes of calls/customer?

A23. Data from the First Quartile Consulting study suggests that the upper quartile peer
 utilities process a higher percentage of total customer interactions in a self-service
 channel. However, the Company cannot share participating utility names, or the

		MI. J. HAI SIUS
Line <u>No.</u>		U-21297
1		data for the utilities that participated in the study, due to a binding non-disclosure
2		agreement.
3		
4	Q24.	Does the Company have any data it can share that reveals where it lags other
5		utilities in the availability and maturity of its self-service offerings?
6	A24.	Yes. The Company has assessed the gaps between its Web self-service offerings
7		and those of two of its closest utility peers - Consumers and ComEd - which I have
8		summarized in Figure 7.
9		
10		Figure 7 DTE Web Self-Service Current Assessment

Figure 7	DTE Web Self-Service Current Assessment
- Sare /	

	Digital Capability	Consumers	ComEd	DTI
	Make a Payment	Ø	$\bigcirc$	0
PAY	Guest Payment	0	$\bigcirc$	$\bigcirc$
	Auto Pay Enrollment	Ø	0	0
	Other Pay Methods (SMS, PayPal, etc.)	0	0	8
	Move In	$\bigcirc$	$\bigcirc$	0
~	Move Out	$\bigcirc$	$\bigcirc$	0
<b>Í</b> sirt	Transfer	$\bigcirc$	$\bigcirc$	0
	Modify Service Order	$\bigcirc$	$\bigcirc$	0
	Restore Service	8	$\bigcirc$	8
00	Payment Arrangement/Plans	$\bigcirc$	$\bigcirc$	8
	Payment Extension (10-day Lock)	$\bigcirc$	$\bigcirc$	8
	Billing Program Enrollments	0	$\bigcirc$	0
	Balance Lookup	0	$\bigcirc$	0
	Bill Summary & Analysis	0	$\bigcirc$	0
	Report Outage	0	$\bigcirc$	0
F	Check Outage Status	$\bigcirc$	$\bigcirc$	0
S	Other Outage Reporting (SMS, Social, etc.)	0	0	8

1 Based on this assessment, and as depicted in Figure 7, the Company has identified 2 opportunities to enhance its existing Web self-service solutions and to create new 3 Web self-service solutions, especially as it relates to enhancing its MIMO and 4 Outage Web solutions, and to the creation of new capabilities for customers who 5 need to process a Collection transaction, for which the Company currently offers 6 no Web self-service solutions. 7 8 In regard to the MIMO and Outage transactions, while the Company continuously 9 improves the Web solutions for these transactions, there remains significant opportunities to further enhance these solutions to increase the ease and 10 11 effectiveness with which customers can complete their transaction (MIMO) and to 12 increase the timeliness and quality of the information provided to customers 13 (Outage). I will discuss the details of these enhancements in my testimony. 14 15 Q25. It appears from the call volume data you provided in Figure 5, that the 16 Company has realized significant reductions in call volumes in recent years. 17 How has it accomplished these reductions? 18 The Company has been strategically investing in its digital self-service capabilities A25. 19 for over 10 years, starting with the 2013 launch of its Outage Web & Mobile App 20 solutions. In 2014, the Company expanded its Web and Mobile App capabilities to 21 include the Billing & Payment transactions, and continued to significantly expand 22 its digital self-service solutions until the launch of its SAP billing system in April 23 of 2017. An overview of these 2013-2017 enhancements is provided here: 24

Line
<u>No.</u>

1

2013 Launch of Outage Web and Mobile	<b>2014</b> Launch of Billing & Payment Web and Mobile App solutions	2015 Launch of Residential Newlook DTE Website
2017 Launch of Commercial +Launch of redesigned Launch of new Landlor		

2	After a slowdown of the pace of tis investments in the digital self-service solutions
3	from April of 2017 through about the end of 2018 – due to the required stabilization
4	of the SAP billing system – the Company from 2019-2022 was able to accelerate
5	its digital self-service enhancement and expansion efforts, as described here:

#### <u>2019</u>

Launched Web Outage Center + Social Media & Web Chat + MIMO Web Enhancements

## <u>2022</u>

Launch of Customer Preference Center + Added Hourly Usage Data to the Web + Ongoing MIMO Web Enhancements <u>2020</u>

Launch of MIMO Web order tracker + MIMO Stop Service IVR Virtual Assistant + Expanded Online Bill History to 18 months

## 2021

Launch of Collection Web order tracker + IVR Restore Self-Service + Promise-to-Pay and High Bill IVR Virtual Assistants + Web Bill Management Tool + New Web Experience for Police/Fire, Municipalities, Outdoor Lighting + Ongoing MIMO Web Enhancements

6

As the Company enhanced and expand its digital self-service solutions from 20122022, it found that more and more customers were engaging in the use of these
solutions, which enabled a net reduction of 1.87 million calls over the 10-year
period (Figure 8).



1



DTE Call Volume Trends (million)





3

4

5

6

7

8

Of note in Figure 8, is the significant drop of 980,000 calls in 2020, which was primarily due to the impacts of the Covid-19 pandemic, during which the Company suspended its noticing and shutoff activities, and during which there was a significant reduction in customer move activity, which together resulted in lower Collection, Billing, and MIMO call volumes (as seen in Figure 5).

As customer move and shutoff activities normalized in 2021 and 2022, the Company expected to see a corresponding increase in call volumes. However, as seen in Figure 8, the actual increase in call volumes from 2020-2022 was not at all significant (~2% increase). This is primarily because customers continued to increase their use of the Company's available digital self-service solutions. As such, the volume of calls to the Contact Center in 2022 remained 897,000 less than they were in 2019 – I will expand on this in my response to Q27.

#### 1 **Q26.** How does the Company measure the level of customer engagement in the use 2 of its digital self-service solutions? 3 A26. The Company assesses customer use of its self-service channels using two metrics: 4 5 1. Self-Service Rate – Measures the total number customer interactions that are 6 completed in a self-service channel, as a percent of total served and self-7 served customer interactions. This metric includes all completed 8 transactional and non-transactional interactions – e.g., if on any given day, 9 customers interact with the Company 50,000 times through a CR or a self-10 service channel, and 40,000 of those interactions were successfully 11 completed in a self-service channel, the Self-Service Rate on that day would 12 be 80%. 13 2. Digital Engagement Rate (DER) – Measures the percent of customers who 14 complete one of the five key transactions in a self-service channel relative to 15 the total number of completed served and self-served transactions - e.g., if 16 on any given day, customers complete a total of 4,000 total MIMO 17 transactions, and 1,200 of those are successfully completed using an 18 available digital self-service solution, the MIMO DER for that day would be 19 30%. 20 21 Q27. Do these metrics support the Company's assertion that customers have more

22

## actively engaged in the use of self-service over the years?

A27. The Company has been tracking the Self-Service rate since 2016 and the DER for
each of the five key transactions since February of 2020. We have seen steady
increases in both metrics since we began tracking them, indicating that increased









<sup>1</sup>Collection DER was 0% in 2020 (no digital selfservice) and MIMO DER was 19% in 2020.

5

6 The average DER of 62% is the simple average of the five key transactions, which 7 has increased from 52% since February of 2020. The individual DERs for each 8 transaction is a function of the number of customers who choose to use a digital 9 self-service solution, and the number of those customers able to successfully 10 complete their transaction in that solution - in other words, to increase the DER for 11 a particular transaction, the digital self-service solutions for that transaction must 12 be seen by customers as an attractive alternative to calling the Contact Center, and 13 must be designed so that a high percentage of customers who choose to use the 14 solution are able to successfully complete their transaction.

Line <u>No.</u>		U-21297
1		In general, the more complex the transaction and the more information customers
2		are asked to provide, the more opportunity there is for customers to "drop-off" and
3		call the Contact Center to complete their transaction.
4		
5		To assess the ease-of-use and effectiveness of the digital self-service solutions, the
6		Company monitors the "completion rate" for each transaction, which is a measure
7		of the total number of completed digital self-service transaction as a percent of the
8		total number of customer attempts to complete that transaction - e.g., if 1,000
9		MIMO digital self-service transactions are completed on given day, and there were
10		a total of 2,500 attempts to compete a MIMO digital self-service transaction, the
11		MIMO digital self-service completion rate for that day would be 40%.
12		
13	Q28.	How does the \$51.3 million portfolio of capital projects reflected in Table 1
14		enable "Reduced Call Volumes"?
15	A28.	The Company's strategy to reduce call volumes is simple - prudently invest in
16		capital projects that will create secure, easy-to-navigate, seamless, and satisfying
17		digital self-service alternatives for customers, which they will increasingly choose
18		to use, and which will be designed to ensure they can successfully complete their
19		transaction without having to call the Contact Center.
20		
21		To that end, the Company allocated the \$51.3 million in capital shown in Table 1,
22		to those projects in Exhibit A-12, Schedule B5.7.3 that will modify the systems in
23		the Customer Technology Platform (Figure 3) to enable the enhancement and
24		expansion of its digital self-service solutions for each of the five key transactions.
25		

1	Q29.	Has the Company assessed the value and benefits to customers of its \$51.3
2		million portfolio of capital investment in its digital self-service solutions?
3	A29.	Yes, and it has done so in consideration of the Commission's November 18, 2022
4		DTE Electric Rate Case No. U-20836 Order, in which the Commission
5		acknowledged that DTE "customers increasingly seek digital transactions", but
6		that DTE "made no effort to show how past expenditures have resulted in benefits
7		to ratepayers or how future investments would do so".
8		
9		While the Company maintains that it did provide, in its U-20836 DTE Electric rate
10		case filing, projections of the value and benefits to customers of its digital self-
11		service investments, there is opportunity in the instant case to provide additional
12		detail. As such, my testimony in the instant case is providing an expanded and
13		detailed cost-benefit analysis for the \$51.3 million portfolio of capital projects,
14		which starts here with a view of the realized and forecasted reductions in call
15		volumes that are being achieved as a result of the implementation of these projects
16		(Figure 10).
17		



## Figure 10 Actual & Forecasted Annual Call Volumes (million)

2

Based on its current 4<sup>th</sup> quartile position versus peer utilities for the number of live 3 4 calls per customers its CRs handle, the Company has determined that to achieve 1<sup>st</sup> 5 quartile performance it must reduce its total handled call volumes to 2.7 million, 6 and is forecasting to achieve that level in 2027 through its implementation of the 7 \$51.3 million portfolio of digital self-service investments. As the Company 8 enhances and expands it digital self-service capabilities through these investments, 9 it will work to increase customer awareness and adoption of the use of these 10 solutions to increase the DER for each of the five key transactions – for example, 11 the Company will leverage its CRs, automated messaging, and customer 12 communications to encourage the use of the digital solutions, and will provide easy 13 access to those solutions through things like "clickable" links in its email and text 14 communications with customers.

15

MJH-31

Line No.

Line No.

> 1 Detailed summaries of these annual call volumes can be found in Exhibit A-24, 2 Schedule N5, which provides a view of the historical and forecasted call volumes 3 for each of the five key transactions. Included in Figure 10, and in the referenced 4 supporting exhibit, are the Company's forecasted reductions in "Other" call 5 volumes. While not categorized by the system or the CRs into one of the five key 6 transactions, we expect that with the full implementation and use of Speech 7 Analytics, these "Other" calls will be automatically assigned to the appropriate 8 transaction. As such, forecasted reductions in "Other" calls included in the total 9 forecasted reductions that are required to reach 2.7 million total calls in 2027.

10

11 As previously described in my testimony, the volume of calls handled in the 12 Contact Center is the most significant driver of Customer Service O&M expense. 13 As such, reducing the volume of calls through enhanced and expanded digital self-14 service alternatives for customers will significantly reduce O&M expense and save 15 customers money through the utility ratemaking process. To quantify the value of 16 these capital investments to customers, the Company has performed a Net Present 17 Value (NPV) analysis of the net annual savings in revenue requirement that is 18 expected to be delivered through the reduction of call volumes shown in Figure 10.

19

#### 20 Q30. Can you describe how an NPV analysis is used to value a capital project?

A30. Yes. An NPV analysis is a commonly used tool to determine how much an
investment, project, or any series of future cash flows is worth in today's dollars.
The NPV analysis forecasts all of the future cash outflows (e.g., project
implementation and ongoing maintenance costs) and inflows (e.g., increased
revenue and/or savings) that a project or investment is expected to generate, and

1		then discounts the annual net cash flows back to the present day to determine if the
2		project or investment is a good or a bad idea. A positive NPV implies that, after
3		accounting for the time value of money, the project or investment is value creating,
4		and therefore a good idea. A negative NPV would imply the opposite, that the
5		project or investment is not value creating, and therefore a bad idea.
6		
7	Q31.	Is the Company providing an NPV analysis for each of the individual projects
8		that make up the total \$51.3 million portfolio of capital projects?
9	A31.	No, the Company is not evaluating the NPV of each of the individual projects in
10		Exhibit A-12, Schedule B5.7.3 that are included in the total \$51.3 million portfolio
11		of digital self-service capital projects.
12		
13	Q32.	Why is the Company not providing an NPV analysis for each of the individual
14		projects included in the \$51.3 million portfolio of capital projects?
		Projects monanda in the serie minor persons of environ projects.
15	A32.	As discussed, the \$51.3 million in capital shown in Table 1, represents a portfolio
15 16	A32.	As discussed, the \$51.3 million in capital shown in Table 1, represents a portfolio of capital projects that provide the aggregate amount of historical, bridge, and test
15 16 17	A32.	As discussed, the \$51.3 million in capital shown in Table 1, represents a portfolio of capital projects that provide the aggregate amount of historical, bridge, and test period capital required to fund the scope of work necessary to modify the systems
15 16 17 18	A32.	As discussed, the \$51.3 million in capital shown in Table 1, represents a portfolio of capital projects that provide the aggregate amount of historical, bridge, and test period capital required to fund the scope of work necessary to modify the systems in the Customer Technology Platform (Figure 3) to enhance and expand the digital
15 16 17 18 19	A32.	As discussed, the \$51.3 million in capital shown in Table 1, represents a portfolio of capital projects that provide the aggregate amount of historical, bridge, and test period capital required to fund the scope of work necessary to modify the systems in the Customer Technology Platform (Figure 3) to enhance and expand the digital self-service solutions to enable "Reduced Call Volumes".
15 16 17 18 19 20	A32.	As discussed, the \$51.3 million in capital shown in Table 1, represents a portfolio of capital projects that provide the aggregate amount of historical, bridge, and test period capital required to fund the scope of work necessary to modify the systems in the Customer Technology Platform (Figure 3) to enhance and expand the digital self-service solutions to enable "Reduced Call Volumes".
15 16 17 18 19 20 21	A32.	As discussed, the \$51.3 million in capital shown in Table 1, represents a portfolio of capital projects that provide the aggregate amount of historical, bridge, and test period capital required to fund the scope of work necessary to modify the systems in the Customer Technology Platform (Figure 3) to enhance and expand the digital self-service solutions to enable "Reduced Call Volumes". This \$51.3 million portfolio of projects is funding the implementation of a "bundle"
15 16 17 18 19 20 21 22	A32.	As discussed, the \$51.3 million in capital shown in Table 1, represents a portfolio of capital projects that provide the aggregate amount of historical, bridge, and test period capital required to fund the scope of work necessary to modify the systems in the Customer Technology Platform (Figure 3) to enhance and expand the digital self-service solutions to enable "Reduced Call Volumes". This \$51.3 million portfolio of projects is funding the implementation of a "bundle" of digital self-service enhancements across the five key transactions. It's this
<ol> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>23</li> </ol>	A32.	As discussed, the \$51.3 million in capital shown in Table 1, represents a portfolio of capital projects that provide the aggregate amount of historical, bridge, and test period capital required to fund the scope of work necessary to modify the systems in the Customer Technology Platform (Figure 3) to enhance and expand the digital self-service solutions to enable "Reduced Call Volumes". This \$51.3 million portfolio of projects is funding the implementation of a "bundle" of digital self-service enhancements across the five key transactions. It's this bundle of enhancements that together will reduce the need for customers to call the
<ol> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>23</li> <li>24</li> </ol>	A32.	As discussed, the \$51.3 million in capital shown in Table 1, represents a portfolio of capital projects that provide the aggregate amount of historical, bridge, and test period capital required to fund the scope of work necessary to modify the systems in the Customer Technology Platform (Figure 3) to enhance and expand the digital self-service solutions to enable "Reduced Call Volumes". This \$51.3 million portfolio of projects is funding the implementation of a "bundle" of digital self-service enhancements across the five key transactions. It's this bundle of enhancements that together will reduce the need for customers to call the Contact Center and enable the achievement of 1st quartile call volumes. In many

1 provide 100% of the funding necessary to implement a particular enhancement for 2 a single transaction. Instead, the individual projects each provide part of the capital 3 required, to fund a portion of the scope of work, to enhance digital self-service 4 solutions for each transaction. 5 6 As such, the value to the customers is not in the execution of the individual projects, 7 but rather in the implementation of the enhanced and expanded digital self-service 8 solutions that the portfolio of projects support, some of which will deliver benefits 9 above and beyond what is forecasted, while others may not achieve the full 10 forecasted benefits. What's important is the aggregate benefit to customers 11 provided by the entire bundle of enhancements. 12 13 Q33. How has the Company applied the NPV analysis to the \$51.3 million portfolio 14 of capital investments? 15 A33. The Company has assessed the annual cash outflows (capital and O&M) for the 16 \$51.3 million portfolio of capital projects across the life of the associated digital 17 self-service assets, which includes the implementation costs for the portfolio of 18 projects, and the ongoing annual costs of maintaining the capital assets. The 19 Company then determined the annual cash inflows (O&M savings) that are 20 forecasted to be provided by the reduction in call volumes enabled by the portfolio 21 of capital projects. The net annual cash flows are then discounted back to today's 22 dollars at the Company's Pre-Tax Weighted Average Cost of Total Capital 23 (WACC) of 6.79% for discounting our Revenue Requirement, per the Final Order

24 in MPSC Case U-20836, to determine the NPV of the capital projects.

25

Line

No.

1 The annual capital project cash outflows represent a cost to customers that results 2 from the Company's recovery of these cash outflows through the ratemaking 3 process. Over time, these Revenue Requirement costs to customers are offset by 4 the Revenue Requirement savings (i.e., cash inflows) to customers that result from 5 the forecasted reduction in call volumes. The future net annual costs or (savings) to 6 customers can then be discounted back to today's dollars to determine the NPV to 7 customers of the portfolio of capital projects. A negative NPV implies the projects 8 are value creating for customers (i.e., saves customers money), while a positive 9 NPV would imply the projects are not value creating for customers (i.e., costs 10 customers money). 11 12 What was the outcome of the NPV analysis for the \$51.3 million in capital Q34. 13 projects? 14 A34. The Company's NPV analysis determined that the NPV to customers of the \$51.3 15 16

- million portfolio of capital projects is a negative \$5.4 million, or the equivalent of a reduction of \$2.12 in Revenue Requirement per customer, implying that these 17 projects are value creating for customers, and therefore are reasonable and prudent 18 in that they provide satisfying digital self-service solutions for customers, reduce 19 call volumes and the associated cost of handling those calls, and save customers 20 money over the life of the project.
- 21

Line

No.

22 The details of this NPV analysis, along with all of the key model assumptions and 23 inputs, are provided in Exhibit A-24, Schedule N6, Page 1, Line 23-24 Column (h). 24 The output of the NPV model for the \$51.3 million in capital projects is summarized 25 in Figure 11.
### Figure 11 Capital Projects Customer NPV (\$ millions)



3

Line

No.

1

2

As seen in Figure 11, customers approximately breakeven in 2026 (i.e., current year Revenue Requirement costs approximately = current year call volume savings) and start to realize net savings of \$4 million in 2027 (i.e., current year call volume savings > current year Revenue Requirement costs), with the net savings growing to an annualized ~\$14 million by 2035, which is sustained in perpetuity.

9

# Q35. Is the Company removing the forecasted call volume savings from its Contact Center operating budget?

A35. Yes. The annual call volume savings for the projected test year are being deducted
from the Customer Service O&M budgets, as discussed in Witness Sparks'
testimony and as reflected in his supporting Exhibit A-13 Schedule C5.7 on Line
5, Column (k) for Customer Records and Collection Expenses, and in footnote 3.

1	Q36.	How is the Company allocating the \$51.3 million in capital across the five key
2		transactions?
3	A36.	The Company is allocating the \$51.3 million in capital across the five key
4		transactions in a manner that aligns with where it sees the most significant
5		opportunity to reduce call volumes. I am providing here an overview of how much
6		historical, bridge, and test period capital is being allocated to each transaction, and
7		the rationale for the amount of capital allocated:
8		
9		1. <u>Collection Self-Service</u>
10		As previously stated, Collection transactions make up one of the largest categories
11		of calls handled (~1 million in 2022) by DTE CRs in the Contact Center, and is the
12		transaction with the most limited number of self-service alternatives available to
13		customers, as evidenced by its 16% DER. As such, an expansion of digital
14		Collection self-service solutions represents a significant opportunity to reduce call
15		volumes and save customers money.
16		
17		To that end, the Company is investing \$16.3 (32%) million of the total capital in the
18		creation of three new Web self-service solutions, which will expand the number of
19		digital self-service alternatives for customers who are engaged in a Collection
20		transaction. This includes the creation of new online tracking tools, new Virtual
21		Assistant (VA) solutions, and new Collection Web digital solutions.
22		
23		2. <u>MIMO Self-Service</u>
24		Like Collections, MIMO transactions are a significant contributor to the volume of
25		calls handled (~720,000 in 2022) by DTE CRs in the Contact Center, and although

its 32% DER is substantially higher than that of the Collection transaction, the Company has identified a number of opportunities to enhance the MIMO Web experience to increase completion rates and the MIMO DER, and to create new MIMO self-service solutions in the IVR.

6 To that end, the Company is investing a total of \$15.7 (31%) million of the total 7 capital to enhance the existing MIMO Web self-service solution, which is occurring 8 in parallel with the migration of the MIMO Web functionality to a cloud-based 9 platform, and to implement MIMO Stop and Start service Virtual Assistants (VAs) 10 in the IVR.

11

4

5

12 3. <u>Outage Self-Service</u>

Customers are very engaged in the use of the Outage digital self-service solutions, as evidenced by the 94% Outage DER. However, the record storm activity and number of customer outages in 2021 has provided greater insight into the opportunities to enhance the Outage self-service experience and the quality of information the Company provides customers during an outage.

18

19To that end, the Company is investing \$9.9 (19%) million of the total capital to the20enhancement of the existing Outage Web experience, including the launch of three21new cloud-based Web portals for Police/Fire, Municipalities, and Outdoor22Lighting.

- 23
- 24 4. <u>Billing Self-Service</u>

1	While the Billing transaction has an 89% DER, indicating customers are very
2	engaged in the available Billing digital self-service solutions, the Company
3	continues to receive a significant number of calls (~670,000 in 2022) from
4	customers who have questions about their bill amount, monthly usage, and other bill
5	information. The Company sees opportunity to provide customers enhanced Billing
6	digital self-service solutions that will provide them answers to these questions
7	without having to call the Contact Center and speak to a CR.
8	
9	To that end, the Company is investing a total of \$5.5 (11%) million of the total
10	capital to implement new online bill and rate analysis tools, to implement a new
11	VA in the IVR that will handle customers bill inquiries, and to enhance the overall
12	Billing Web customers experience as part of the transition of the Billing Web
13	functionality to a cloud-based platform.
14	
14 15	5. <u>Payment Self-Service</u>
14 15 16	<ul><li>5. <u>Payment Self-Service</u></li><li>The Company processes millions of customer payments every year, with the</li></ul>
14 15 16 17	<ol> <li><u>Payment Self-Service</u></li> <li>The Company processes millions of customer payments every year, with the majority of them completed using one of the Company's digital self-service</li> </ol>
14 15 16 17 18	<ul> <li>5. <u>Payment Self-Service</u></li> <li>The Company processes millions of customer payments every year, with the majority of them completed using one of the Company's digital self-service solutions, as indicated by the 82% Payment DER. However, given that the</li> </ul>
14 15 16 17 18 19	5. <u>Payment Self-Service</u> The Company processes millions of customer payments every year, with the majority of them completed using one of the Company's digital self-service solutions, as indicated by the 82% Payment DER. However, given that the Company handles over 32 million payment transactions every year, even small
14 15 16 17 18 19 20	5. <u>Payment Self-Service</u> The Company processes millions of customer payments every year, with the majority of them completed using one of the Company's digital self-service solutions, as indicated by the 82% Payment DER. However, given that the Company handles over 32 million payment transactions every year, even small increases in the Payment DER would result in significant reductions in call volumes
14 15 16 17 18 19 20 21	5. <u>Payment Self-Service</u> The Company processes millions of customer payments every year, with the majority of them completed using one of the Company's digital self-service solutions, as indicated by the 82% Payment DER. However, given that the Company handles over 32 million payment transactions every year, even small increases in the Payment DER would result in significant reductions in call volumes versus the ~720,000 Payment calls handled in 2022.
14 15 16 17 18 19 20 21 22	5. <u>Payment Self-Service</u> The Company processes millions of customer payments every year, with the majority of them completed using one of the Company's digital self-service solutions, as indicated by the 82% Payment DER. However, given that the Company handles over 32 million payment transactions every year, even small increases in the Payment DER would result in significant reductions in call volumes versus the ~720,000 Payment calls handled in 2022.
<ol> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>23</li> </ol>	5. <u>Payment Self-Service</u> The Company processes millions of customer payments every year, with the majority of them completed using one of the Company's digital self-service solutions, as indicated by the 82% Payment DER. However, given that the Company handles over 32 million payment transactions every year, even small increases in the Payment DER would result in significant reductions in call volumes versus the ~720,000 Payment calls handled in 2022. To that end, the Company is investing a total of \$3.9 (7%) million of the total capital
<ol> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>23</li> <li>24</li> </ol>	5. <u>Payment Self-Service</u> The Company processes millions of customer payments every year, with the majority of them completed using one of the Company's digital self-service solutions, as indicated by the 82% Payment DER. However, given that the Company handles over 32 million payment transactions every year, even small increases in the Payment DER would result in significant reductions in call volumes versus the ~720,000 Payment calls handled in 2022. To that end, the Company is investing a total of \$3.9 (7%) million of the total capital to enhance the Authenticated (customers who log-in to their online account) and

1		solutions. Together, the Authenticated and Guest Pay solutions accounted for
2		almost 9 million digital self-service Payment attempts in 2022. Increasing the
3		ability of customers to successfully complete their Web payment attempt on their
4		first try will improve the customer experience and mitigate Payment calls from
5		customers who "drop-off" of the Web and call the Contact Center.
6		
7	Q37.	In what order will you discuss the \$51.3 million portfolio of digital self-service
8		capital projects?
9	A37.	I will discuss the \$51.3 million in historical, bridge, and test period digital self-
10		service capital projects in the following order, aligning my discussion with each of
11		the five key transactions:
12		
13		1. MIMO Digital Self-Service (\$15.7 million)
14		2. Outage Digital Self-Service (\$9.9 million)
15		3. Billing Digital Self-Service (\$5.5 million)
16		4. Collection Digital Self-Service (\$16.3 million)
17		5. Payment Digital Self-Service (\$3.9 million)
18		
19	Q38.	Can you provide here additional details regarding how the \$51.3 million
20		portfolio of capital projects is allocated across the five key transactions?
21	A38.	Yes. There are 15 individual projects (i.e., business cases) in Exhibit A-12,
22		Schedule B5.7.3, that makeup the total \$51.3 million portfolio of historical, bridge,
23		and test period capital. Table 2 on the following page provides a summary of how
24		much of the associated total capital for these 15 projects is allocated to each of the

Line No. 1 five key transactions, by calendar year of the investment, as such the 2023/2024 2 amounts will differ slightly from what is shown in Exhibit A-12, Schedule B5.7.3. 3 4 Table 2

U-21297 Capital Exhibit A-1	7.3	Ca	pital Alloca	ition (\$ m	illions) - By	Transaction	Туре		
Project Name	Line No.	Year	Total Project Capital (\$ millions)	ΜΙΜΟ	Outage	Billing	Payment	Collection	Total Capital Allocated
Digital Experience Group	36	2021	\$1.6	\$1.6					\$1.6
Digital Transactional Experience	37	2021	\$4.4	\$0.5	\$3.0		\$0.4	\$0.5	\$4.4
Bill Management	26	2021	\$2.2			\$2.2			\$2.2
IVR Virtual Assistants	43	2021	\$2.3			\$1.2		\$1.1	\$2.3
Kiosk Experience	45	2021	\$1.5				\$1.5		\$1.5
	20	21 Total	\$12.0	\$2.1	\$3.0	\$3.4	\$1.9	\$1.6	\$12.0
Journey Work Product Transformation Team	44	2022	\$6.9	\$3.0	\$1.6			\$2.3	\$6.9
CR&B Program Enhancements	16	2022	\$2.0	\$0.3		\$0.1		\$0.1	\$0.4
API Integration Security Gateway - API Layer	24	2022	\$1.6	\$0.8				\$0.8	\$1.6
Customer Closed Loop Development	32	2022	\$0.5					\$0.5	\$0.5
EFC - Outage Status	38	2022	\$12.3		\$5.3				\$5.3
IVR Virtual Assistants	43	2022	\$1.3	\$1.3					\$1.3
Social Technologies	56	2022	\$0.2			\$0.2			\$0.2
	20	22 Total	\$24.7	\$5.4	\$6.9	\$0.2	\$0.0	\$3.6	\$16.2
Billing Web Self-Service	27	2023	\$0.9			\$0.9			\$0.9
Collection Web Self-Service	30	2023	\$6.5					\$6.5	\$6.5
MIMO Web Self-Service	48	2023	\$5.1	\$5.1					\$5.1
Payment Web Self-Service	49	2023	\$0.9				\$0.9		\$0.9
	20	23 Total	\$13.4	\$5.1		\$0.9	\$0.9	\$6.5	\$13.4
Billing Web Self-Service	27	2024	\$1.4			\$1.4			\$1.4
Collection Web Self-Service	30	2024	\$5.4			,		\$5.4	\$5.4
MIMO Web Self-Service 48			\$4.0	\$4.0					\$4.0
Payment Web Self-Service	49	2024	\$1.4				\$1.4		\$1.4
	20	24 Total	\$12.2	\$4.0		\$1.4	\$1.4	\$5.4	\$12.2
20	21-202	4 Total	\$62.3	\$16.6	\$9.9	\$5.9	\$4.2	\$17.1	\$53.8

### **Digital Self-Service Capital Funding**

5 In regard to the information in Table 2, there are several important things that 6 should be noted:

7

8

- The portfolio of 15 projects referenced in the table total \$62.3 million in • 2021-2024 calendar-year capital.
- 10 • Of the total \$62.3 million in calendar-year capital, \$53.8 million was 11 allocated to the enhancement and expansion of the digital self-service 12 solutions across the five key transactions.

1	•	The difference between the \$62.3 million in total project capital, and the
2		\$53.8 million in allocated capital, is due to the partial allocation of capital
3		from the CR&B Program Enhancements and EFC – Outage Status projects,
4		which are highlighted in red, and which I will discuss in subsequent sections
5		of my testimony.
6	•	The \$53.8 million in allocated capital, is the equivalent of \$51.3 million
7		when adjusted to reflect the historical, bridge, and test periods in the instant
8		case.
9	•	In 2021 and 2022, 11 projects contributed a total of \$28.2 million in
10		calendar-year capital to fund the modifications to the Customer Technology
11		Platform (Figure 3) that were necessary to enhance and expand the digital
12		self-service solutions. In most cases, an individual project allocated a
13		portion of its capital to system changes for each of the five key transactions
14		- for example, the 2021 Digital Transactional Experience project allocated
15		capital to enhance and expand digital self-service solutions for the MIMO,
16		Outage, Payment, and Collection transactions (as shown in Figure 2).
17	•	In 2023 and 2024, a total of \$25.6 million in capital has been consolidated
18		within just four projects, each aligned with one of the five key transactions,
19		and each providing 100% of the capital required to modify the systems in
20		the Customer Technology Platform (Figure 3) to enhance and expand the
21		digital self-service solutions for that transaction (as shown in Figure 2).
22		Note, the scope of each of these four projects is focused only on the Web
23		channel, which is where the Company sees the most significant opportunities
24		for improvement in 2023 and 2024:

Line

No.

	M. J. HATSIOS U-21297
	1. Line 27 – Billing Web Self-Service
	2. Line 30 – Collection Web Self-Service
	3. Line 48 – MIMO Web Self-Service
	4. Line 49 – Payment Web Self-Service
MIM	O Digital Self-Service
Q39.	When and why did the Company launch its first MIMO digital self-service
	solution?
A39.	The Company launched the current iteration of its MIMO Web self-service solution
	in April of 2017, concurrent with its implementation of the SAP CR&B system
	(i.e., Customer 360). At that time, the Company was handling over 1.0 million
	MIMO calls in the Contact Center and was interested in creating a MIMO Web
	self-service solution that would engage customers in a satisfying experience and
	reduce the volume of calls.
Q40.	Did customers choose to actively engage in the MIMO Web self-service
	solution after it was launched?
A40.	While the engagement of MIMO customers in the Web steadily increased, and the
	volume of calls steadily decreased, the Company still handled over 900,000 MIMO
	calls in 2019.
Q41.	Why did the MIMO Web solution not provide a more significant reduction in
	call volumes from its launch in 2017 through 2019?
A41.	There are several reasons why the MIMO Web solution did not drive more
	substantial decreases in the volume of MIMO calls through 2019. First of all,

Line <u>No.</u>

1		MIMO is a more inherently complex transaction, with customers asked to go
2		through a number of steps in the process to complete their transactions, especially
3		to start service. Secondly, as previously indicated it took a significant amount of
4		time to stabilize the SAP billing system, which limited the ability of the Company
5		to commit resources to address known defects and cumbersome process flows in
6		the MIMO Web solution that were preventing customers from completing their
7		transaction.
8		
9		Together, these two factors resulted in very low MIMO Web completion rates
10		( $\sim$ 20%). As such, many customers who chose to engage in the use of the MIMO
11		Web solution were finding they were unable to complete their transaction, forcing
12		them to drop off of the Web and call the Contact Center.
13		
15		
14	Q42.	Can you describe the steps a customer must go through to complete a MIMO
14 15	Q42.	Can you describe the steps a customer must go through to complete a MIMO Web transaction?
14 15 16	<b>Q42.</b> A42.	Can you describe the steps a customer must go through to complete a MIMO Web transaction? Yes. Figure 12 provides a view of the MIMO process flow for a customer
14 15 16 17	<b>Q42.</b> A42.	Can you describe the steps a customer must go through to complete a MIMO Web transaction? Yes. Figure 12 provides a view of the MIMO process flow for a customer attempting to start service with DTE on the Web. It includes each of the steps and
14 15 16 17 18	<b>Q42.</b> A42.	Can you describe the steps a customer must go through to complete a MIMO Web transaction? Yes. Figure 12 provides a view of the MIMO process flow for a customer attempting to start service with DTE on the Web. It includes each of the steps and inputs required to complete the transaction, from initiating the request through
14 15 16 17 18 19	<b>Q42.</b> A42.	Can you describe the steps a customer must go through to complete a MIMO Web transaction? Yes. Figure 12 provides a view of the MIMO process flow for a customer attempting to start service with DTE on the Web. It includes each of the steps and inputs required to complete the transaction, from initiating the request through order confirmation, and for some customers checking on the status of their order.
14 15 16 17 18 19 20	<b>Q42.</b> A42.	Can you describe the steps a customer must go through to complete a MIMO Web transaction? Yes. Figure 12 provides a view of the MIMO process flow for a customer attempting to start service with DTE on the Web. It includes each of the steps and inputs required to complete the transaction, from initiating the request through order confirmation, and for some customers checking on the status of their order.
<ol> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> </ol>	<b>Q42.</b> A42.	Can you describe the steps a customer must go through to complete a MIMO Web transaction? Yes. Figure 12 provides a view of the MIMO process flow for a customer attempting to start service with DTE on the Web. It includes each of the steps and inputs required to complete the transaction, from initiating the request through order confirmation, and for some customers checking on the status of their order.
<ol> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> </ol>	<b>Q42.</b> A42.	Can you describe the steps a customer must go through to complete a MIMO Web transaction? Yes. Figure 12 provides a view of the MIMO process flow for a customer attempting to start service with DTE on the Web. It includes each of the steps and inputs required to complete the transaction, from initiating the request through order confirmation, and for some customers checking on the status of their order.
<ol> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>23</li> </ol>	<b>Q42.</b> A42.	Can you describe the steps a customer must go through to complete a MIMO Web transaction? Yes. Figure 12 provides a view of the MIMO process flow for a customer attempting to start service with DTE on the Web. It includes each of the steps and inputs required to complete the transaction, from initiating the request through order confirmation, and for some customers checking on the status of their order.
<ol> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>23</li> <li>24</li> </ol>	<b>Q42.</b> A42.	Can you describe the steps a customer must go through to complete a MIMO Web transaction? Yes. Figure 12 provides a view of the MIMO process flow for a customer attempting to start service with DTE on the Web. It includes each of the steps and inputs required to complete the transaction, from initiating the request through order confirmation, and for some customers checking on the status of their order.

Line <u>No.</u> 1 2 3 Figure 12 MIMO Start Service Web Process Flow



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As seen in Figure 12, starting service with DTE is a multi-step process, and while it is the same over the phone with a CR as it is on the Web, when a customer chooses to complete the transaction on the Web they don't have the benefit of help from a CR, which can result in customers getting "stuck" and either abandoning the transaction and trying again, or calling the Contact Center.

Line <u>No.</u>		<b>M. J. HATSIOS</b> U-21297
1		
2	Q43.	How has the Company reduced the complexity of the MIMO Web self-service
3		solution over the last several years to increase the completion rates?
4	A43.	In 2020, the Company began a focused effort to address the complexity of the
5		MIMO Web solution, with the goal of increasing completion rates by eliminating
6		cumbersome process flows, fixing system defects, modifying Web business rules,
7		and improving the ease with which customers could navigate the solution. These
8		efforts resulted in a significant increase to the overall MIMO Web completion rate
9		from 20% (2019) to 38% (2020).
10		
11		The Company continued to enhance the MIMO Web self-service solution in
12		2021/2022 through the investment of \$6.2 million in capital (Table 2), which was
13		provided by five projects in Exhibit A-12, Schedule B5.7.3:
14		
15		1. Line 36 – Digital Experience Group (\$1.6 million)
16		2. Line 37 – Digital Transactional Experience (\$0.5 million)
17		3. Line 44 – Journey Work Product Transformation Teams (\$3.0 million)
18		4. Line 16 – CR&B Program Enhancements (\$0.3 million)
19		5. Line 24 – API Integration Security Gateway – API Layer (\$0.8 million)
20		
21		Together, these five projects provided all of the 2021/2022 capital required to
22		modify the systems in the Customer Technology Platform (Figure 3) to further
23		enhance the MIMO Web self-service solution. The Digital Experience Group,
24		Digital Transactional Experience, and Journey Work Product Transformation Team
25		projects provided the capital required to modify the Web Channel. The CR&B

**M. J. HATSIOS** Line U-21297 No. 1 Program Enhancements project provided the capital required to modify the SAP-2 ISU and CRM systems (i.e., CR&B). The API Integration Security Gateway – API 3 Layer project provided the capital required to modify the associated API interfaces 4 and integrations. 5 6 Q44. What types of enhancements were funded by the \$6.2 million in capital 7 investment in the MIMO Web self-service solution in 2021/2022? 8 A44. In addition to addressing identified technical defects that were stopping customers 9 from completing their MIMO Web transaction, the \$6.2 million in 2021/2022 10 capital funded the following MIMO Web enhancements: 11 12 2021 MIMO Web Enhancements 13 New iconography (i.e., "tiles") and improved layout 14 Customized journey depending on if new, current, or former customer 15 Updated pages describing what's needed to start service ٠ 16 New page for customers who want to switch account owners 17 New comprehensive FAQ pages • 18 New sign-in page for current or former customers 19 Display any recently scheduled and completed MIMO customer orders 20 Display any outstanding issues that require resolution before a customer can ٠ 21 start service – e.g., theft blocks, failed prior positive identification, etc. 22 23 2022 MIMO Web Enhancements 24 MIMO Web start-service migrated to a cloud-based platform. 25 Customers only need to enter last four digits of social security number.

		M. J. HATSIOS
Line <u>No.</u>		U-21297
1		• Remove and/or replace confusing error messages.
2		• Remove redundant and confusing tiles.
3		• Ability to validate international addresses - from customers moving to
4		DTE's service territory from outside the United States.
5		
6		The 2022 enhancements were completed concurrently with the transition of the
7		MIMO Web Start service functions to a cloud-based platform. A more descriptive
8		and detailed summary of all of the 2021/2022 MIMO Web self-service
9		enhancements can be found in Exhibit A-24, Schedule N7.
10		
11	Q45.	What other MIMO digital self-service solutions has the Company
12		implemented for which it is seeking capital recovery in the instant case?
13	A45.	As seen in Table 2, the Company invested \$1.3 million in 2022 to implement a
14		MIMO Start service Virtual Assistant (VA), which is a portion of the total \$3.6
15		million in VA capital funding for which the Company is seeking recovery in the
16		instant case. The remaining \$2.4 million in capital was allocated to implement VA
17		solutions for the Collection and Billing transactions in 2021 (Table 2), which I will
18		discuss in the section of my testimony dedicated to the digital self-service solutions
19		for these transactions.
20		
21	Q46.	Why is the Company investing in VA technology as part of its strategy to
22		enhance and expand its digital self-service solutions?
23	A46.	A significant number of our customers continue to pick-up the phone and dial the
24		Company's 1-800 number to complete a transaction, as evidenced by the 4.6
25		million interactions completed in the IVR in 2022, and the previously discussed

4.23 million customers who completed their interaction through a CR. As such, the
 Company continuously identifies opportunities to enhance its existing IVR self service solutions, and to implement new technologies that will enhance the
 customer experience and reduce call volumes.

5

# Q47. What are the advantages of an IVR VA solution versus a traditional IVR self service solution?

A47. Traditional IVR solutions are limited to simpler transactions that are easily
navigated through touch-tone inputs and simple and limited voice responses. VAs
can complete more complicated transactions and can be more conversational in
nature than a traditional IVR solution. As such, VAs can be used to provide
customers with more complicated inquiries and transactions an efficient and secure
IVR self-service solution that can handle their request without the need to speak to
a CR.

15

# Q48. What has been the aggregate impact of the 2021/2022 MIMO digital self service capital investments?

A48. The 2021/2022 MIMO digital self-service capital investments described in my
testimony have increased MMIO Web completion rates from 38% (2020) to 43%
(2022) and the MIMO DER from 19% (2020) to 32% (2022). To account for the
previously discussed Covid-19 impacts on 2020 MIMO call volumes, the Company
maintains it's reasonable to compare the 2022 MIMO call volumes to 2019, which
indicates a net reduction of 173,000 calls resulting from these enhancements.

# Q49. Can you elaborate on the 2022 migration of the MIMO Web Start service solution to the cloud?

3 A49. Yes. The MIMO Web self-service solution is run on the on-premise hosted Web 4 platform, which as described by Witness Sharma, is aging. Also, as part of DTE's 5 cloud strategy to move all non-core applications to the cloud, the Company's 6 Website has been under-going the transition from a hosted, on-premise solution, to 7 a cloud-based solution, as described in the DTE IT 5-year plan. In 2022, the MIMO 8 start-service transaction was the first of the MIMO Web transactions to move to the 9 cloud, with plans to migrate the MIMO Stop and Transfer transactions to the cloud 10 in 2023 and 2024.

11

# Q50. Is the Company continuing to invest capital in the MIMO digital self-service solutions in 2023/2024?

14 A50. Yes. As previously stated, the MIMO Web completion rate in 2022 was 43%. This 15 is the overall completion rate, which consists of the Start (32% completion rate), 16 Stop (78% completion rate), and Transfer (60% completion rate) service 17 transactions. The low Start service Web completion rates are primarily driven by 18 the 1) failure of the customer to provide personal identifying information, or failure 19 of the system to validate a person's identify from the personal information 20 provided, 2) errors by the customer when providing the address to which they are 21 moving, or system errors that prevent the validation of that address, 3) inability, or 22 unwillingness, of the customer to create an online profile, and 4) unwillingness, or 23 inability, of the customer to pay any outstanding balance while completing their 24 Start service request.

1		In 2023/2024, the Company will continue to invest capital in the enhancement of
2		the MIMO Web solution to increase completion rates for all three of the MIMO
3		Web transactions, with a focus on eliminating the failure points for the Start service
4		transaction that I described above. Providing MIMO Web solutions with high
5		completion rates will provide customers a significantly improved experience, and
6		will increase the confidence with which the Company can offer and direct
7		customers to the use of these solutions, which will increase the MIMO DER and
8		provide further reductions in MIMO call volumes.
9		
10	Q51.	How much capital is the Company investing in the 2023/2024 MIMO Web Self-
11		Service project?
12	A51.	The Company is investing \$8.4 million in 2023 bridge (\$4.1 million) and 2024 test
13		(\$4.3 million) period capital in the MIMO Web Self-Service project (Exhibit A-12,
14		Schedule B5.7.3, Line 48), which provides 100% of the funding necessary to
15		modify the systems in the Customer Technology Platform (Figure 3) to further
16		enhance the MIMO Web solution.
17		
18	Q52.	What types of MIMO Web enhancements will be enabled by the \$8.4 million
19		2023/2024 capital investment?
20	A52.	In parallel with the ongoing migration of the MIMO Stop (2023) and Transfer
21		(2024) solutions to the cloud, the Company will use the \$8.4 million in 2023/2024
22		capital to enhance the MIMO Web User Experience and User Interfaces (UX/UI),
23		and to address known failure points that are preventing more customers from being
24		able to successfully complete their MIMO Web transaction. To that end, the

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2023/2024 MIMO Web Self-Service capital project will fund the following enhancements:

- Accepting security deposits in lieu of customers being required to provide Personal Identification (PID) information, during which a significant number of customers drop-off the Web because the system, through its Experian checks, can't validate the data/customer's identity or often times because customers don't want to provide it.
- Continuing to improve the address search and validation MIMO Web functionality, which remains a significant point of failure for customers.
- Making it much easier for customers who want to change the scheduled date
   of their MIMO order on the Web the Company receives ~40,000 calls per
   year from customers who are calling to reschedule their MIMO order,
   creating an opportunity to reduce calls by directing customers to the change
   order function in MIMO Web, and ensuring the solution is easily navigated
   to mitigate these phone calls.
- Incorporating Web chat across the MIMO Web transactions to provide
  assistance to customers who get "stuck" in the process reducing the cost
  of a phone call by keeping customers in the Web and connecting them with
  a live Web Chat agent who can get them through the process.
- Expanding the availability of the MIMO Web self-service solution to include
   new business customers, who today have no alternative but to call the
   Contact Center, due to the inability of the system to connect with the State
   of Michigan's business Tax ID verification system in 2022, MIMO

<b>.</b> .		M. J. HATSIOS
Line <u>No.</u>		0-21297
1		requests from new business customers accounted for ~18,000 calls to the
2		Contact Center.
3		
4	Q53.	What are the forecasted outcomes and customer benefits of the portfolio of
5		2021-2024 MIMO digital self-service capital projects you just described?
6	A53.	The Company is forecasting that the historical, bridge, and test period MIMO
7		digital self-service capital investments will enable an increase in the MIMO DER
8		to 72% by 2026, which will reduce the volume of MIMO calls to the Contact Center
9		to a sustained 400,000 calls. This represents a net reduction of 317,000 calls versus
10		2022, providing annualized and sustained O&M savings of \$3.59 million.
11		
12		These outcomes are summarized in Exhibit A-24, Schedule N5, and reflected in the
13		previously discussed NPV analysis in Exhibit A-24, Schedule N6.
14		
15	Outag	ge Digital Self-Service Projects
16	Q54.	What types of enhancements has the Company implemented for the Outage
17		digital self-service solutions in 2021/2022?
18	A54.	The focus for the Outage transaction in 2021/2022 was to improve the usability,
19		ease-of-navigation, and quality of the data provided to customers who were
20		reporting or checking on the status of storm related outages using the Web. To that
21		end, the Company funded and implemented the following enhancements:
22		
23		• Migration of Police and Fire, Municipalities, and Outdoor Lighting portals
24		to new cloud-based sites.

Line No.		M. J. HATSIOS U-21297
1		• Design and navigation enhancements on dteenergy.com and Outage Center
2		following accessibility standards.
3		• Added COVID-related messaging for customer and employee safety.
4		• Improved customer-facing error messages.
5		• Added notification options for reporting of wires down between poles.
6		• Integrated Web Outage with the new cognitive address search to make it
7		easier for customers to search and find address.
8		• Completed changes required to support the pending 2023 Advanced
9		Distribution Management System (ADMS) launch.
10		• Integrated with new "Where is My Order" (WISM) and Premise Power
11		Status (PPS) to implement Error Free Communication (EFC) - Outage
12		Status enhancements – which I will discuss in Part 6 of my testimony related
13		to projects that create "Enhanced Customer Interactions".
14		
15		A more descriptive and detailed summary of the 2021/2022 Outage Web
16		enhancements can be found in Exhibit A24, Schedule N8.
17		
18	Q55.	How much capital did the Company invest to implement the 2021/2022 Outage
19		Web self-service enhancements?
20	A55.	In 2021/2022, the Company invested \$9.9 million in three projects (Table 2) to
21		enhance the Outage Web self-service solution. These projects are included in
22		Exhibit A-12, Schedule B5.7.3 as follows:
23		
24		1. Line 37 – Digital Transactional Experience (\$3.0 million)
25		2. Line 44 – Journey Work Product Transformation Teams (\$1.6 million)

Line		M. J. HATSIOS U-21297
<u>No.</u>		
1		3. Line 38 – EFC – Outage Status (\$5.3 million)
2		
3		Together these three projects provided the 100% of the resources and funding to
4		modify the Web Channel, the CR&B system, and the associated Integration layers
5		in the Customer Technology Platform (Figure 3) as necessary to implement the
6		2021/2022 Outage Web enhancements.
7		
8	Q56.	What have been the outcomes and customer benefits of the already
9		implemented 2021/2022 Outage Web self-service enhancements?
10	A56.	The 2021/2022 Outage Web self-service enhancements have improved the
11		visibility of the Outage Web page content, improved the quality of the information
12		presented to customers regarding their outage, and made navigation of the Outage
13		Web site easier for customers.
14		
15		Together, these improvements have resulted in a 9% increase in Outage Web DER
16		from 61.4% in 2021 to 70.6% in 2022, for customers reporting an outage. The
17		volume of mitigated calls from this increased DER is dependent on storm activity,
18		but for the purposes of sizing the impact, for every 1,000,000 outage reports
19		attempted by customers on the Web, 90,000 calls would be avoided as a result of a
20		9% DER increase. In 2022, DTE customers attempted to report 1.36 million
21		Outages on the Web, which means that the 9% increase in Outage reporting Web
22		DER mitigated what would have been an additional 122,000 calls to the Contact
23		Center.
24		

# Q57. How have the three new cloud-based sites you described in your list of Outage Web enhancements improved the performance of the transitioned Web portals?

A57. These three new cloud-based sites – for the Police/Fire, Municipality, and Outdoor
Lighting Web portals – have resulted in a reduction from what was four hours of
planned downtime per month for the on-premise sites, to zero hours of planned
downtime per month for the cloud-based solutions, with overall availability for
these solutions rising from 98.24% (6.43 days per year of downtime) to 99.5% (1.83
days per year total downtime), meaning that customers would experience fewer
instances of the site being unavailable due to maintenance or system issues.

11

# Q58. Is the Company continuing to invest capital in the enhancement of the Outage digital self-service solutions in 2023/2024?

# A58. Yes. However, these ongoing enhancements will be funded as part of the total 2023/2024 capital allocated to the Company's EFC – Outage Status initiative, which I will discuss in Part 6 of my testimony along with the rest of the portfolio of capital projects that enable "Enhanced Customer Interactions".

18

# Q59. What are the expected outcomes and customer benefits of the portfolio of 20 2021-2024 capital investments in the Outage experience?

# A59. The Company is forecasting that the total historical, bridge, and test period Outage digital self-service investments described in my testimony, will increase the Outage to 97% by 2026, which will result in a sustained annual volume of 198,000 Outage calls. This represents a decrease of 115,000 calls versus 2022, which will result in an annualized and sustained O&M savings of \$1.30 million.

т :		M. J. HATSIOS
Line <u>No.</u>		0-21297
1		
2		These outcomes are summarized in Exhibit A-24, Schedule N5, and are reflected
3		in the previously described NPV analysis in Exhibit A-24, Schedule N6.
4		
5	Billin	g Digital Self-Service
6	Q60.	What types of enhancements and new functionality were funded by the
7		Company's capital investments in Billing digital self-service in 2021/2022?
8	A60.	As reflected in Table 2, the Company invested \$3.6 million in capital, provided by
9		four projects, to modify the systems in the Customer Technology Platform to
10		develop and implement new Billing digital self-service solutions. These projects
11		are included in Exhibit A-12, Schedule B5.7.3 as follows:
12		
13		1. Line 26 – Bill Management (\$2.2 million)
14		2. Line 16 – CR&B Program Enhancements (\$0.1 million)
15		3. Line 56 – Social Technologies (\$0.2 million)
16		4. Line 43 – IVR Virtual Assistants (\$1.2 million)
17		
18		In 2021, the Bill Management project provided funding for 100% of the scope of
19		work required to create a new online bill analyzer for customers – this included the
20		funding of modifications to the Web Channel, the CR&B system, and the API
21		integration layers. In 2022, the CR&B Program Enhancements project provided
22		funding to address identified CR&B system defects that were impacting the online
23		bill analyzer, while the Social Technologies project provided the funding for the
24		Web Channel changes required to build Web chat capability in the online bill
25		analyzer, providing customers access to a live resource should they have questions

Lina		M. J. HATSIOS
<u>No.</u>		0-21297
1		about their bill or the use of the analyzer. Separately, the IVR Virtual Assistants
2		(VAs) project, provided 100% of the funding required, across the Customer
3		Technology Platform, to implement a VA to handle customer billing inquiries in
4		the IVR.
5		
6	Q61.	How does the online bill analyzer work and how does it help customers analyze
7		their bills?
8	A61.	The new online bill analyzer allows customers to understand factors that impact
9		their energy usage and to explore potential cost saving opportunities to reduce their
10		monthly bills. Prior to the implementation of this functionality, customers utilizing
11		the Web would only have access to static prior month and prior year usage and
12		temperature comparisons, along with a comparison of the number of days in the
13		billing cycle versus the prior month and year. The new online bill analyzer consists
14		of two components, a bill impact analyzer and a bill simulator. Together, these two
15		elements provide customers with an estimate of those items that impacted their
16		current bill – usage, weather, billing days – along with the ability to simulate their
17		next bill based on usage forecasts, and the impact of any usage reductions they
18		could realize by changing their behavior (Figure 13).
19		

### Line No.

1

#### Figure 13 **Online Bill Analyzer Tool**



2

#### 3 Have customers been actively engaged in using the online bill analyzer, and if Q62. 4

### so, has it resulted in a reduction in Billing calls to the Contact Center?

5 A62. The most recently available data indicates that over 182,000 unique DTE Electric 6 customers accessed the online bill analyzer tools over 357,000 times from January 7 through about mid-October 2022, with only 0.9% (1,800 customers) calling the 8 Contact Center with a billing inquiry within a week of using the tool. This data 9 implies that a large number of customers are using the online bill analyzer, and that 10 very few feel the need to call the Contact Center to discuss their bill.

11

12 The Company compared this data to a control group of 484,000 customers who 13 from January through about mid-October 2022, viewed their bill online but did not access the online bill analyzer. For this control group of customers, 1.5% called 14 15 the Contact Center within a week of viewing their bill online. This data indicates 16 that customers who utilize the bill analyzer may be up to 35% less likely to call the

Line <u>No.</u>		M. J. HATSIOS U-21297
1		Contact Center when compared to those who view their bill online without using
2		the analyzer.
3		
4	Q63.	What type of Billing VA solution was implemented in the IVR in 2021?
5	A63.	The IVR VA project allocated \$1.2 million in capital (Table 2) to the
6		implementation of a Billing VA in August of 2021, which provides an automated
7		response to the questions customers have about the amount of their bill – which the
8		Company refers to as a "High Bill" inquiry.
9		
10	Q64.	Has the High Bill VA significantly reduced the volume of calls from customers
11		who call with questions about the amount of their bill?
12	A64.	In 2022, the first full year of implementation of the High Bill VA, a total of 1% of
13		the inquiries handled by the VA were completed and contained in the IVR,
14		indicating that there is significant opportunity to enhance the solution. As such,
15		like the MIMO VAs, the Company will continue to enhance the High Bill VA
16		solution through the funding provided by the Contact Center Application Health
17		Sustainment project (Exhibit A-12, Schedule B5.7.2, Line 3) described in Witness
18		Sharma's testimony in the instant case, with the goal of increasing the percent of
19		requests successfully handled and contained in the IVR.
20		
21	Q65.	Is the Company planning on continuing to invest capital in the Billing digital
22		self-service solutions in 2023/2024?
23	A65.	Yes. In parallel with the migration of the Billing Web transactions to a new cloud
24		platform, the Company is going to invest capital in 2023/2024 to fund the
25		implementation of a new Billing Web UX/UI experience. This new experience will

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1		incorporate the impacts and emerging learnings from the implementation of the
2		TOD rates, and will streamline the customer's overall Billing experience,
3		particularly in regard to the information they see when they log-in to the DTE
4		website. Today, when customers log-in to their online account, prominently
5		displayed to them is their current bill amount due and a link to pay. To enhance the
6		experience, the Company will use the 2023/2024 Web self-service capital to more
7		prominently display for customers comparisons of their current bill to prior bills,
8		their usage patterns, and opportunities to reduce usage and save money, which will
9		be supported by ongoing enhancements to the previously discussed online bill
10		analyzer.
11		
12	Q66.	How much capital is the Company investing in the 2023/2024 Billing digital
13		self-service solutions?
14	A66.	The Company is investing \$2.0 million in bridge (\$0.7 million) and test (\$1.3
15		million) period capital to the Billing Web Self-Service project (Exhibit A-12,
16		Schedule B5.7.3, Line 27), which provides 100% of the funding required to modify
17		the systems in the Customer Technology Platform (Figure 3) to further enhance the
18		Billing Web self-service solution.
19		
20	Q67.	What are the expected outcomes and customer benefits of the portfolio of
21		2021-2024 Billing digital self-service capital projects described in your
22		testimony?
23	A67.	The historical, bridge, and test period Billing digital self-service capital investments
24		described in my testimony, are forecasted to increase the Billing DER to 92% by
25		2026, which will reduce Billing calls to a sustained annual 528,000 per year. This

		M. J. HATSIOS
Line <u>No.</u>		U-21297
1		represents a reduction of 146,000 in calls versus 2022, which will result in
2		annualized and sustained savings of \$1.66 million.
3		
4		These outcomes are summarized in Exhibit A-24, Schedule N5, and are reflected
5		in the previously described NPV analysis in Exhibit A-24, Schedule N6.
6		
7	Colle	ction Digital Self-Service
8	Q68.	Why is the Company pursuing digital self-service alternatives for customers
9		who find themselves in the Collection process?
10	A68.	As things began to normalized post-Covid (2020) the Company saw Collection call
11		volumes increase from 680,000 (2020) to ~1,000,000 (2022), as shown in Figure 5.
12		At an incremental cost of \$11.34 per handled call, the cost of handling these calls
13		in the Contact Center in 2022 exceeded \$11.3 million. As such, the Company is
14		investing in an expansion of its Collection digital self-service solutions to reduce
15		Collection calls volumes and the associated cost of handling those calls.
16		
17	Q69.	What are the types of Collection transactions for which customers contact the
18		call center?
19	A69.	In 2022, the Company processed almost 400,000 Collection transactions, which
20		generated the ~1,000,000 Collection calls handled by DTE CRs, of which:
21		
22		• 32% were from DTE Electric and Gas Customers who were either shutoff
23		for nonpayment and needed to process a restore of service, or who were
24		inquiring about a pending shutoff,

1       • 16% are from customers enrolling in, or un-enrolling from a Shut         2       Protection Plan (SPP).         3       • 10% are from customers requesting a Promise-to-Pay (PTP) hold to get m         4       time to pay their current bill.         5       • 8% are from non-low income customers enrolling in a Paym         6       Arrangement (PA) allowing them to pay their past due balance over time         7       *         8       The remaining 34% of Collection calls were related to general inquiries, ager         9       assistance inquiries, home heating credit inquiries, requests for medical hold         10       Winter Protection Plan (WPP) enrollments, refunds, etc.         11       *         12 <b>Q70.</b> To which Collection transactions is the Company committing capital to creating in a With the Collection self-service solutions?         14       A70. The Company, based on its own experience with several recently implemented P         15       Collection self-service solutions, and its assessment of what's offered by util         16       peer companies, has chosen to invest capital in Web self-service solutions for D         17       Electric AMI customers who want to pay the required amount to restore the         18       service (Restores), for DTE Electric and DTE Gas customers who want to enroll         19       a Promise-to-Pay (PTP) hold to give them more time	Line <u>No.</u>		U-21297
<ul> <li>Protection Plan (SPP).</li> <li>10% are from customers requesting a Promise-to-Pay (PTP) hold to get main time to pay their current bill.</li> <li>8% are from non-low income customers enrolling in a Paym Arrangement (PA) allowing them to pay their past due balance over time Arrangement (PA) allowing them to pay their past due balance over time assistance inquiries, home heating credit inquiries, requests for medical hold Winter Protection Plan (WPP) enrollments, refunds, etc.</li> <li>Q70. To which Collection transactions is the Company committing capital to create new digital self-service solutions?</li> <li>A70. The Company, based on its own experience with several recently implemented Pair Collection self-service solutions, and its assessment of what's offered by util peer companies, has chosen to invest capital in Web self-service solutions for Darrow in the service (Restores), for DTE Electric and DTE Gas customers who want to enrol a Promise-to-Pay (PTP) hold to give them more time to pay their current bill, a low income DTE Electric and DTE Gas customers who are not eligible a low income payment plan and want to pay their past due balance over time us a Payment Arrangement (PA).</li> </ul>	1		• 16% are from customers enrolling in, or un-enrolling from a Shutoff
<ul> <li>10% are from customers requesting a Promise-to-Pay (PTP) hold to get m time to pay their current bill.</li> <li>8% are from non-low income customers enrolling in a Paym Arrangement (PA) allowing them to pay their past due balance over time Arrangement (PA) allowing them to pay their past due balance over time assistance inquiries, home heating credit inquiries, requests for medical hol Winter Protection Plan (WPP) enrollments, refunds, etc.</li> <li><b>Q70.</b> To which Collection transactions is the Company committing capital to create new digital self-service solutions?</li> <li>A70. The Company, based on its own experience with several recently implemented P Collection self-service solutions, and its assessment of what's offered by util peer companies, has chosen to invest capital in Web self-service solutions for D Electric AMI customers who want to pay the required amount to restore th service (Restores), for DTE Electric and DTE Gas customers who want to enrol a Promise-to-Pay (PTP) hold to give them more time to pay their current bill, a for non-low income DTE Electric and DTE Gas customers who are not eligible a low income payment plan and want to pay their past due balance over time us a Payment Arrangement (PA).</li> </ul>	2		Protection Plan (SPP).
<ul> <li>4 time to pay their current bill.</li> <li>5 • 8% are from non-low income customers enrolling in a Paym Arrangement (PA) allowing them to pay their past due balance over time Arrangement (PA) allowing them to pay their past due balance over time The remaining 34% of Collection calls were related to general inquiries, ager assistance inquiries, home heating credit inquiries, requests for medical hol Winter Protection Plan (WPP) enrollments, refunds, etc.</li> <li>10 Winter Protection transactions is the Company committing capital to create new digital self-service solutions?</li> <li>14 A70. The Company, based on its own experience with several recently implemented P Collection self-service solutions, and its assessment of what's offered by util peer companies, has chosen to invest capital in Web self-service solutions for D Electric AMI customers who want to pay the required amount to restore th service (Restores), for DTE Electric and DTE Gas customers who want to enrol a Promise-to-Pay (PTP) hold to give them more time to pay their current bill, a for non-low income DTE Electric and DTE Gas customers who are not eligible a low income payment plan and want to pay their past due balance over time us a Payment Arrangement (PA).</li> </ul>	3		• 10% are from customers requesting a Promise-to-Pay (PTP) hold to get more
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<ul> <li>9 assistance inquiries, home heating credit inquiries, requests for medical hole</li> <li>10 Winter Protection Plan (WPP) enrollments, refunds, etc.</li> <li>11</li> <li>12 Q70. To which Collection transactions is the Company committing capital to create</li> <li>13 new digital self-service solutions?</li> <li>14 A70. The Company, based on its own experience with several recently implemented P</li> <li>15 Collection self-service solutions, and its assessment of what's offered by util</li> <li>16 peer companies, has chosen to invest capital in Web self-service solutions for D</li> <li>17 Electric AMI customers who want to pay the required amount to restore the</li> <li>18 service (Restores), for DTE Electric and DTE Gas customers who want to enrol?</li> <li>19 a Promise-to-Pay (PTP) hold to give them more time to pay their current bill, a</li> <li>20 for non-low income DTE Electric and DTE Gas customers who are not eligible</li> <li>21 a low income payment plan and want to pay their past due balance over time us</li> <li>22 a Payment Arrangement (PA).</li> </ul>	8		The remaining 34% of Collection calls were related to general inquiries, agency
10Winter Protection Plan (WPP) enrollments, refunds, etc.1112Q70.To which Collection transactions is the Company committing capital to crest13new digital self-service solutions?14A70.The Company, based on its own experience with several recently implemented P15Collection self-service solutions, and its assessment of what's offered by util16peer companies, has chosen to invest capital in Web self-service solutions for D17Electric AMI customers who want to pay the required amount to restore the18service (Restores), for DTE Electric and DTE Gas customers who want to enrol?19a Promise-to-Pay (PTP) hold to give them more time to pay their current bill, a20for non-low income DTE Electric and DTE Gas customers who are not eligible21a low income payment plan and want to pay their past due balance over time us22a Payment Arrangement (PA).	9		assistance inquiries, home heating credit inquiries, requests for medical holds,
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<ul> <li>service (Restores), for DTE Electric and DTE Gas customers who want to enrol</li> <li>a Promise-to-Pay (PTP) hold to give them more time to pay their current bill, a</li> <li>for non-low income DTE Electric and DTE Gas customers who are not eligible</li> <li>a low income payment plan and want to pay their past due balance over time use</li> <li>a Payment Arrangement (PA).</li> </ul>	12 13 14 15 16	<b>Q70.</b> A70.	To which Collection transactions is the Company committing capital to create new digital self-service solutions? The Company, based on its own experience with several recently implemented IVR Collection self-service solutions, and its assessment of what's offered by utility peer companies, has chosen to invest capital in Web self-service solutions for DTE
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<ul> <li>for non-low income DTE Electric and DTE Gas customers who are not eligible</li> <li>a low income payment plan and want to pay their past due balance over time use</li> <li>a Payment Arrangement (PA).</li> </ul>	12 13 14 15 16 17 18	<b>Q70.</b> A70.	To which Collection transactions is the Company committing capital to create new digital self-service solutions? The Company, based on its own experience with several recently implemented IVR Collection self-service solutions, and its assessment of what's offered by utility peer companies, has chosen to invest capital in Web self-service solutions for DTE Electric AMI customers who want to pay the required amount to restore their service (Restores), for DTE Electric and DTE Gas customers who want to enroll in
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22 a Payment Arrangement (PA).	12 13 14 15 16 17 18 19 20	<b>Q70.</b> A70.	To which Collection transactions is the Company committing capital to create new digital self-service solutions? The Company, based on its own experience with several recently implemented IVR Collection self-service solutions, and its assessment of what's offered by utility peer companies, has chosen to invest capital in Web self-service solutions for DTE Electric AMI customers who want to pay the required amount to restore their service (Restores), for DTE Electric and DTE Gas customers who want to enroll in a Promise-to-Pay (PTP) hold to give them more time to pay their current bill, and for non-low income DTE Electric and DTE Gas customers who are not eligible for
	12 13 14 15 16 17 18 19 20 21	<b>Q70.</b>	To which Collection transactions is the Company committing capital to create new digital self-service solutions? The Company, based on its own experience with several recently implemented IVR Collection self-service solutions, and its assessment of what's offered by utility peer companies, has chosen to invest capital in Web self-service solutions for DTE Electric AMI customers who want to pay the required amount to restore their service (Restores), for DTE Electric and DTE Gas customers who want to enroll in a Promise-to-Pay (PTP) hold to give them more time to pay their current bill, and for non-low income DTE Electric and DTE Gas customers who are not eligible for a low income payment plan and want to pay their past due balance over time using
23	12 13 14 15 16 17 18 19 20 21 22	<b>Q70.</b> A70.	To which Collection transactions is the Company committing capital to create new digital self-service solutions? The Company, based on its own experience with several recently implemented IVR Collection self-service solutions, and its assessment of what's offered by utility peer companies, has chosen to invest capital in Web self-service solutions for DTE Electric AMI customers who want to pay the required amount to restore their service (Restores), for DTE Electric and DTE Gas customers who want to enroll in a Promise-to-Pay (PTP) hold to give them more time to pay their current bill, and for non-low income DTE Electric and DTE Gas customers who are not eligible for a low income payment plan and want to pay their past due balance over time using a Payment Arrangement (PA).

24 1. <u>Restores</u>

1	In 2022, the Company processed ~192,000 Restores for customers whose service
2	was disconnected for nonpayment. Over 178,000 of these Restores were for DTE
3	Electric customers, of which 63% (~106,000) were for customers who paid the full
4	amount required to restore their service, without the need for assistance or to enroll
5	in a payment plant. To offer these customers an alternative to having to speak to a
6	CR, the Company in early 2021 implemented the ability for DTE Electric AMI
7	customers to complete a Restore in the IVR.
8	
9	In 2022, ~23,600 DTE Electric restores were completed in the IVR, the equivalent
10	of a 13% electric Restore DER. Expansion of this functionality to the Web will
11	further engage DTE Electric AMI customers in the use of digital self-service to
12	complete their Restore transaction, which will increase the overall Collection DER
13	and contribute to the achievement of the forecasted call volume reductions shown
14	in Figure 10.
15	
16	2. <u>Promise-to-Pay (PTP) Holds</u>
17	In October of 2021, the Company implemented a PTP VA in the IVR to provide
18	customers who call to request more time to pay their bill an easy self-service
19	alternative. In 2022, the Company processed ~98,000 PTP holds for customers who
20	requested more time to pay their bill, of which 38,700 were completed using the
21	VA, the equivalent of a 39% PTP DER. Expanding this self-service functionality
22	to the Web will further engage customers in the use of digital self-service to
23	complete their PTP transaction, which will increase the overall Collection DER and
24	contribute to the achievement of the call volume reductions shown in Figure 10.
25	



Figure 14 **Utility Peers Offering Web Payment Arrangements** 



Line

10 While the eligibility requirements vary across these utility offerings, they all allow 11 customers to engage online with a self-service solution to check their eligibility and 12 enroll in a PA, which allows customers to pay their outstanding bill in monthly 13 installments over a specified period. Creating the ability for customers to enroll in 14 a PA on the Web, will further engage customers in the use of digital self-service 15 solutions, which will increase the overall Collection DER, and contribute to the 16 achievement of the forecasted call volume reductions in Figure 10.

1	Q71.	Why is the Company not implementing a digital self-service solution for low
2		income customers who want to enroll in a Shutoff Protection Plan (SPP)?
3	A71.	SPPs have a very high failure rate, with typically over 70% of customers unable to
4		successfully fulfill their payment obligations while on SPP. And while customers
5		can enroll in a second SPP within a 12-month period, ultimately many of these
6		customers fail again, find themselves shutoff for nonpayment, and struggle to find
7		the money to restore their service.
8		
9		Given the high SPP failure rates, the Company has chosen not to pursue a digital
10		self-service solution for SPP because it prefers instead that its low income
11		customers call the Contact Center. This will allow CRs to connect these customers
12		to available energy assistance funding, and to enroll them in a payment plan that
13		fits their needs and maximizes the probability that they will successfully pay down
14		their arrears and avoid shutoff – e.g., the Low Income Self-Sufficiency Plan (LSP)
15		and the Payment Stability Plan (PSP).
16		
17	Q72.	Which 2021/2022 projects provided the necessary funding to expand the
18		Company's Collection digital self-service solutions?
19	A72.	There are six projects (Table 2), that provided a total of \$5.2 million in 2021/2022
20		capital to modify the systems in the Customer Technology Platform (Figure 3) to
21		create several new Collection digital self-service solutions. These projects are
22		included in Exhibit A-12, Schedule B5.7.3 as follows:
23		

- 241. Line 37 Digital Transactional Experience (\$0.5 million)
- 25 2. Line 44 Journey Work Product Transformation Team (\$2.2 million)

### Line <u>No.</u>

Line		M. J. HATSIOS U-21297
<u>No.</u>		
1		3. Line 16 – CR&B Program Enhancement (\$0.1 million)
2		4. Line 24 – API Integration Security Gateway & API Layer (\$0.8 million)
3		5. Line 32 – Customer Closed Loop Development (\$0.5 million)
4		6. Line 43 – IVR Virtual Assistant (\$1.1 million)
5		
6		The Digital Transactional Experience and Journey Work Product Transformation
7		Team projects provided a total of \$2.7 million in capital to fund all the required
8		Web channel modifications. The CR&B Program Enhancements, API Integration
9		Security Gateway - API Layer, and Customer Closed Loop Development projects
10		provided a total of \$1.4 million in capital to fund all the required CR&B system,
11		and API modifications. Separately, the IVR VA project provided 100% of the 2021
12		funding required to implement the previously discussed PTP IVR VA solution.
13		
14	Q73.	Can you describe the implemented 2021/2022 Collection digital self-service
15		enhancements?
16	A73.	Yes. The Company invested \$4.1 million in capital in two new Web solutions for
17		the Collection transaction. The first was the implementation of an online Collection
18		order-tracker (2021) for customers processing a Restore or validating their low-
19		income status, and the second was the development of new functionality on the
20		Web for DTE Electric AMI customers who want to make a payment to restore their
21		electric service (2022).
22		
23		1. Online Collection Order Tracker
24		In July of 2021, the Company launched an online Collection order tracker, which is
25		being used by customers who have been disconnected for non-payment and are

processing a restore, as well as those customers who are validating their low-income
status for the purposes of receiving energy assistance or enrolling in a payment plan.
Receiving a shutoff notice, being disconnected for nonpayment, and seeking energy
assistance can be stressful for customer, who often repeatedly call the Contact
Center to check on the status of their restore or the validation of their low-income
status.
To provide these customers an alternative to having to call the Contact Center, the
Company created the online Collection order tracker to give these customers
visibility into the status of their restore and/or low-income validation in a manner
what would mitigate the need for them to call the Contact Center (Figure 15).



3

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Completed

The Collection order tracker was enabled by the same "Where Is My Order" (WISMO) application implemented in 2020 for the MIMO transaction as part of the Customer Closed Loop Development project, which provided the \$0.5 million in capital required to fund the back-end CR&B system changes needed to enhance the WISMO application for the Collection transaction.

7

9 The WISMO application is part of the Customer Technology Platform and is 10 reflected in Figure 3 as the Service Order Management system. WISMO enables 11 us to track the status of a customer order or inquiry and provides data that is used 12 to present order status to both customers in the online portal, and to the CRs in the 13 CRM system. I will discuss the details of the Customer Closed Loop Development

### Line No.

M. J. HATSIOS U-21297
project in Part 6 of my testimony, as part of the portfolio of projects that align with
the creation of "Enhanced Customer Interactions".
2. <u>Collection Web Restores</u>
As previously discussed, the Company in 2021 implemented the capability for DTE
Electric AMI customers to complete a Restore transaction in the IVR, which now
accounts for 13% of all completed electric Restore transactions. In parallel with
identifying opportunities to enhance the IVR solution, the Company has been
designing and developing a new Web Restore solution for DTE Electric AMI
customers, which is scheduled to go-live in February of 2023. This solution will
present customers with a summary of the required payment to restore service, allow
customers to pay online, provide customers with confirmation that their payment
has been accepted, and provide confirmation of when they can expect service to be
restored (Figure 16).

Line <u>No.</u>

Make Payment

### Figure 16 Collection Web Residential Electric AMI Restores

2



### Restore Amount Due



4

Line

No.

1

### 5 Q74. Can you expand on the previously discussed PTP VA IVR solution?

A74. The Company allocated \$1.1 million in capital (Table 2) to the implementation of
the PTP IVR VA in October of 2021, which places a lock on the accounts of
customers who request additional time to pay their current bill. A PTP lock
removes the accounts of these customers from the Company's revenue recovery
processes for up to 10-days, providing customers additional time to pay their bill.
As I previously discussed, in 2022 customers completed 38,700 PTP transactions
in the IVR VA that otherwise would have been handled by a CR over the phone.
25		solutions in 2023/2024 to support these new Web solutions?
24	Q76.	How much capital is the Company investing in the Collection Web self-service
23		
22		include Web self-service tools and solutions for customers on LSP and PSP.
21		expand PTP Web eligibility to include more customers (e.g., commercial), and
20		customers - e.g., allow DTE Gas customers to process a Restore on the Web,
19		identified customer failure points, and expand the eligibility to include more
18		solutions to enhance the UX/UI experience, address any system defects and
17		In 2024, the Company will continue to invest in these Collection Web self-service
16		
15		pay over time (PA).
14		(PTP) or who are non-low income with past due balances that they would like to
13		DTE Electric and DTE Gas customers who need more time to pay their current bill
12		the Company in 2023 will launch new PTP and PA Web self-service solutions for
11		amount required to restore their electric service. In addition to this functionality,
10		the Web for DTE Electric AMI-enabled customers who are able to pay the full
9	A75.	In February of 2023, the Company will launch a Restore self-service solution on
8		self-service solutions for customers in 2023/2024?
7	Q75.	What are the Company's plans for expanding the available Collection Web
6		
5		percent of requests successfully handled and contained in the IVR.
4		in Witness Sharma's testimony in the instant case, with the goal of increasing the
3		Health Sustainment project (Exhibit A-12, Schedule B5.7.2, Line No. 3) described
2		VA solution through the funding provided by the Contact Center Application
1		Like the MIMO and High Bill VAs, the Company will continue to enhance the PTP

1	A76.	The Company is investing a total of \$10.9 million in bridge period (\$5.3 million)
2		and test period (\$5.6 million) capital in the Collection Web Self-Service project
3		(Exhibit A-12, Schedule B5.7.3, Line 30), which provides 100% of the funding
4		required to implement the new Collection Web self-service solutions (2023), and
5		to continue to enhance and expand the scope of these solutions (2024).
6		
7	Q77.	What are the expected outcomes and customer benefits of all the 2021-2024
8		Collection digital self-service investments you described in your testimony?
9	A77.	The Company is forecasting that the historical, bridge, and test period investments
10		in the Collection digital self-service solutions described in my testimony, will
11		increase in the Collection DER to 61% by 2027. This increased DER is expected
12		to reduce Collection call volumes to a sustained 643,000 calls per year. This
13		represents a net reduction of 352,000 calls versus 2022, which will result in an
14		annualized and sustained O&M savings of \$3.99 million.
15		
16		These outcomes are summarized in Exhibit A-24, Schedule N5, and are reflected
17		in the previously described NPV analysis in Exhibit A-24, Schedule N6.
18		
19	Paym	ent Digital Self-Service
20	Q78.	Can you please describe the scope of work completed for the \$0.4 million in
21		2021 capital invested in the Payment Web self-service transaction?
22	A78.	Yes. As seen in Table 2, the Company allocated \$0.4 million in 2021 capital from
23		the Digital Transactional Experience project to fund to the enhancement of the Web
24		channel. These enhancements were primarily related to fixing defects and

<u>No.</u>

1

improving the look and feel of the previously discussed Authenticated and Guest Pay Web solutions.

3

2

4 Q79. Are there any other Payment digital self-service solutions in which the 5 Company invested capital in 2021/2022, and for which it is seeking recovery? 6 A79. Yes, the Company has invested in our Kiosk payment network in the Kiosk 7 Experience project on Line 45 of Exhibit A-12, Schedule B5.7.3. Until October 8 2021, our cash channel was operated by DivDat (vendor) through shared kiosks at 9 70 locations throughout the Company's service territory. In 2021, the Company 10 chose to migrate to CityBase (vendor) and invested \$1.5 million in 2021 (Table 2) 11 historical period capital to purchase 45 DTE-branded CityBase kiosks. These 12 standalone DTE-branded kiosks modernized and streamlined the customer 13 experience and allow the Company to more strategically managing the kiosk 14 network footprint based on our understanding of our cash customers' needs.

15

# Q80. Is the Company planning to continue to invest capital in its Payment digital self-service solutions in 2023/2024?

18 Yes. Payments make up the largest volume of the Company's five key transactions, A80. 19 with customers completing over 32.8 million payment transactions in 2022. Of 20 these total completed Payment transactions, 27% were completed through the 21 Autopay program, 23% were completed on the Web/Mobile Web, 12% were 22 completed in the Mobile App, 11% were through an electronic transfer of funds 23 (ETF), 8% were completed in the IVR, 2% were handled by a CR, and 1% were 24 from cash payments in the Company's Kiosks. The remainder of the total payments 25 were made by mail (16%).

1		
2		While the Payment DER of 82% in 2022 is the third highest of the five key
3		transactions, with almost 33 million completed Payment transactions every year,
4		increasing the Payment DER even by a small amount will lead to significant
5		reductions in call volumes and savings for customers. As such, the Company is
6		allocating capital to the ongoing enhancement of the digital self-service Payment
7		solutions.
8		
9	Q81.	Where is the Company focusing its 2023/2024 Payment digital self-service
10		capital investments?
11	A81.	In 2022, over 8.6 million customer Payment interactions were attempted by our
12		customers on the Web, which included over 6.0 million payment attempts from
13		"Authenticated" customers who log-in to their online account, over 2.5 million
14		payment attempts from "non-authenticated" customers who do not log-in to their
15		account but instead use the Guest Pay option, and 0.15 million customers who
16		attempted to enrolled in Autopay.
17		
18		Given the large volume of total attempted Web payments, the Company is focusing
19		its 2023/2024 Payment digital self-service investments on the Web, with a focus on
20		improving the Payment completion rates to reduce the volume of calls to the
21		Contact Center.
22		
23	Q82.	Has the Company assessed the opportunity to reduce Payment call volumes
24		through improvements in the Payment Web self-service solutions?

Line
No.

1	A82.	Yes. The overall Web Payment completion rate was ~76% in 2022, implying that
2		customers experienced ~2.0 million failed Web Payment attempts. An analysis of
3		the 2022 data for Authenticated Web payments found that there were $\sim$ 780,000
4		"unique" customers who failed on their first payment attempt, but that the majority
5		were ultimately successful in using the Web, or another self-service channel, to
6		make their payment on the same day, or shortly thereafter. However, over 55,000
7		(7%) of these customers wound up completing their payment through a CR in the
8		Contact Center.
9		
10		Unfortunately, the Company cannot track the activity of customers who attempted
11		to make a payment through the Guest Pay channel until they complete their
12		transaction, as they do not provide any identifying information. However, the
13		Company does know that Guest Pay completion rates are lower than those for
14		Authenticated customers (~55% versus ~86%) indicating there is significant
15		opportunity to enhance the solution to mitigate the potential for customers to call
16		the Contact Center and speak to a CR.
17		
18		As previously stated, small increases in the Payment DER will provide significant
19		reductions in call volumes. This is especially true if large numbers of customers
20		

who regularly make payments through a CR are transitioned to a digital self-service
solution, like the Web. Therefore, as the Company continues to promote and
provide customers easy access to the Web Payment solutions (e.g., active links to
Web pay in customer email notifications; offering customers who call a Mobile
Web pay text link), it must ensure that that these customers can successfully

<b>.</b> .		M. J. HATSIOS
Line <u>No.</u>		U-21297
1		complete their transaction, so that they will continue to make the Web their
2		Payment channel of choice.
3		
4		To increase Web Payment Authenticated and Guest Pay completion rates, the
5		Company will invest 2023/2024 capital in projects that:
6		
7		1. Enhance the Payment Web UX/UI experience.
8		2. Address failure points in the process that are preventing customers from
9		successfully completing their payment (e.g., Address Search).
10		3. Simplify the process for Autopay customers to update their saved payment
11		methods, which today requires the customer to unenroll and reenroll in the
12		program and can lead to calls to a CR.
13		4. Implement more descriptive error messages, so that when customers fail in
14		their attempt to make a payment on the Web, they will know why and can
15		increase the likelihood of success on their next attempt.
16		
17	Q83.	How much 2023/2024 capital is the Company investing in the Payment Web
18		self-service solutions?
19	A83.	The Company is investing a total of \$2.0 million in bridge period (\$0.7 million)
20		and test period (\$1.3 million) capital in the Payment Web Self-Service project
21		(Exhibit A-12, Schedule B5.7.3, Line 49), which provides 100% of the funding
22		required to implement the planned 2023/2024 Payment Web self-service
23		enhancements.
24		

1	Q84.	What are the expected outcomes and customer benefits of the 2021-2024
2		Payment digital self-service projects described in your testimony?
3	A84.	The Company is forecasting that the historical, bridge, and test period investments
4		in the Web Payment digital self-service solutions described in my testimony, will
5		increase the Payment DER to over 83% by 2026, enabling the Company to reach
6		long-term and sustainable Payment call volumes of 450,000 a year. This represents
7		a reduction of over 270,000 calls versus 2022, which will result in annualized and
8		sustained O&M savings of \$3.06 million.
9		
10		These outcomes are summarized in Exhibit A-24, Schedule N5, and reflected in the
11		previously described NPV analysis in Exhibit A-24, Schedule N6.
12		
13	Part 5	5. Projects Creating Operational Efficiencies
14	Q85.	What is included in this section of your testimony?
15	A85.	This section of my testimony will include a discussion of the portfolio of 22 projects
16		in Exhibit A-12, Schedule B5.7.3 – Line No. 15-20, 22, 23, 25, 28, 29, 31, 35, 39,
17		40-42, 50, 54-56, 58 - that align with and enable "Increased Operational
18		Efficiencies", and which total \$30.2 million in historical (\$2.3 million), bridge
19		(\$17.2 million), and test (\$10.7 million) period capital, as reflected in Table 1.
20		
21	Q86.	How is the Company deploying the \$30.2 million in capital to projects that will
22		create operational efficiencies that save customers money?
23	A86.	The Company's strategy to create operational efficiencies is simple - prudently
24		invest in capital projects that leverage automations, new technologies, and process

Line <u>No.</u>	<b>M. J. HATSIOS</b> U-21297
1	improvements to increase the efficiency and effectiveness with which the Company
2	manages its Customer Service operations.
3	
4	To that end, the Company is investing the \$19.7 million in historical, bridge, and
5	test period capital to those projects that will modify the Contact Center, Field
6	Management, and CR&B Systems of Record (Figure 3) to enable the achievement
7	of increased operational efficiencies. The Company is investing an additional \$10.5
8	million in historical, bridge, and test period capital to those projects that will modify
9	the CR&B systems, create additional test environments, and advance the system's
10	monitoring applications to improve the efficiency and capability by which we
11	manage customer systems and with which IT projects are developed and deployed
12	into production:
13	
14	1. Call Handling Efficiency – \$9.2 million in capital to improve the efficiency
15	and effectiveness with which customer calls are identified, routed, and
16	handled in the Contact Center.
17	2. Telephony System Efficiency – \$5.1 million in capital to improve the
18	efficiency with which the Company manages its telephony systems and
19	increase the resiliency and accessibility of these systems for customers.
20	3. Field Operations Efficiency – \$3.7 million in capital to improve the
21	efficiency of Collection field activities in RM&P, and meter reading field
22	activities in Billing & Metering.
23	4. Back-Office Efficiency – \$1.7 million in capital to provide for the more
24	efficient processing and management of the core revenue recovery (i.e.,

Line <u>No.</u>		U-21297
1		collection) and billing back-office operations, including management of
2		instances of theft and fraud.
3		5. Systems and IT Project Efficiency – \$10.5 million in capital to maintain and
4		enhance our customer systems (CR&B and Legacy applications), accelerate
5		the development, Q/A, and testing of Customer IT projects and prevent
6		unplanned CR&B system outages and avoidable costs.
7		
8	Q87.	What are the total annualized savings the Company will realize through its
9		investment in projects that "Create Operational Efficiencies"?
10	A87.	By 2027, the \$30.2 million in capital investments will provide an annualized
11		Customer Service O&M savings of \$2.9 million. Of these total savings:
12		
13		1. 47% will come from call volume reductions above and beyond those already
14		discussed and described in my testimony in the instant case.
15		2. 33% will come from CR attrition enabled by reductions in the average
16		duration of a handled call, with reduced total "call-minutes" resulting in the
17		need for fewer CRs to effectively handle the calls.
18		3. $\sim$ 20% will come from CR attrition (19%) enabled will come from reducing
19		"shrinkage" or non-productive time with optimal management of contact
20		center work management and reduction in CR wait time (1%) during
21		unplanned system outages discussed in System and IT Efficiencies.
22		
23		The subsequent portions of my Q&A responses, for this part of my testimony, will
24		provide the detailed scope and expected outcomes and benefits of the Company's
25		investments in each of the five identified areas of opportunity.

Line <u>No.</u>		U-21297
1		
2	Conta	act Center Efficiency
3	Q88.	Can you please describe those Contact Center efficiency projects and the
4		efficiency savings they are forecasted to provide?
5	A88.	Yes. The Company is investing \$9.2 million in historical, bridge, and test period
6		capital in seven projects that will: 1) Enhance the ability of the Contact Center to
7		capture call handling efficiencies that reduce Average Handle Time (AHT); 2)
8		better identify the reason for a customer's call; and 3) route the call more efficiently
9		to the most appropriate resource – which could be a CR or a VA – and to reduce
10		the length of time it takes for a CR to handle a call. I will discuss each of these
11		projects in the order in which they appear in Exhibit A-12, Schedule B5.7.3.
12		
13		1. <u>Line 25 – Avaya Platform Upgrade</u>
14		The Company is investing \$2.1 million in test period capital to implement an
15		upgrade to the Contact Center's Avaya Platform in 2024 that will reduce Average
16		Handle Time (AHT) and provide O&M savings to the customer. Avaya is one of
17		the core customer systems and is responsible for call handling and the identification
18		and routing of calls in the IVR to the most appropriate CR or self-service IVR
19		solution. This upgrade will provide for the consolidation of information from
20		multiples systems to provide:
21		
22		• "Screen-Pop" technology that will provide CRs a complete view of the
23		customer's information on a single screen – including the customer's name,
24		their business partner number, their premise address, and a complete history
25		of their interactions and transaction history.

Line <u>No.</u>	U-21297
1	• Provide the foundation for the development of "Omni-Channel" capabilities
2	in 2025, which will allow for the transfer of data between the self-service
3	channels and the CR systems – i.e., whatever data the customer has already
4	input into a self-service solution will transfer to the CR systems in the event
5	the customer fails to complete their self-service transaction and needs to
6	speak to a CR. Reducing handle time since more information about the
7	reason for the customer's call is passed and minimizing customer frustration
8	with having to provide their information twice.
9	• Enhanced Virtual Hold Technology (VHT) that will provide customers the
10	opportunity to select a time during which they would like a callback during
11	periods of long wait times to speak to a CR – knowing why a customer is
12	calling and when to call them back allows the CR time to prepare to handle
13	the inquiry, resulting in lower call handle times.
14	
15	The above enhancements are forecasted to lower the AHT across the entire
16	population of calls by an average of 15 seconds. We expect customer benefit
17	realization from the reduction in AHT to begin in 2025 and be fully leveraged by
18	2027 resulting in annualized O&M savings and customer benefit of \$729,000, as
19	reflected in Exhibit A-24, Schedule N9 Operational Efficiencies Line No. 1.
20	
21	2. Line 31 – Contact Center Enablement
22	DTE is investing \$0.73 million in 2023 bridge period (\$0.33 million) and test period
23	(\$0.40 million) capital to standardize the CR screens for handling Collection calls
24	to match the Collection call flow. The screens in CRM would be customized with
25	a default layout that retrieves information rapidly and in a clear, concise manner,

1	eliminating the need for the CR to search and switch between multiple screens. All
2	the information required would be provided upfront so the CR can more efficiently
3	handle a collection call. Time saved can allow the CR to provide more information
4	to customers and answer their questions related to availability of energy assistance
5	and eligibility that would be most favorable for the customer given their particular
6	situation or status. All CRs are required to provide energy assistance information
7	as the first option for customers struggling to pay their past-due bills / arrears.
8	
9	The Contact Center handled ~1 million collection calls in 2022 and this call type
10	has the highest AHT at 734 seconds vs. the overall AHT across call types of 630
11	seconds. We expect the standardization of the CR Collection screens will shorten
12	the length of a collection call by 8 seconds, providing annualized O&M savings to
13	the customer of ~\$93,000 by 2027. See Exhibit A-24 Schedule N9 Operational
14	Efficiencies Line No. 2.
15	
16	3. <u>Line 35 – Enhanced Training Environments</u>
17	DTE invested \$0.57 million in 2021 historical period (\$0.32 million) and 2022
18	bridge period (\$0.25 million) capital to enhance our CR Training Environments,
19	which have not been upgraded since the implementation of the Customer 360 SAP
20	system in April of 2017. Since that time, the Company has identified and fixed
21	defects in the production system, and deployed numerous other changes and new
22	functionality, which has created a gap between the training and production systems.
23	
24	The upgrade will close that gap by providing a set of refreshed data that is consistent
25	with production, and by developing client interfaces with customer systems that

1	will allow transactions to be performed in a hands-on training environment, as
2	opposed to the current state which often times requires the use of static and obsolete
3	screenshot contents to train employees, resulting in a suboptimal experience for
4	customers as it takes longer for employees to learn how to efficiently and
5	effectively navigate the changes due to a lack of adequate training.
6	
7	4. Line 42 – IVR Natural Language Processing (NLP)
8	The Company completed its investigation into the available NLP technologies in
9	2020, and based on those investigations, is investing \$0.9 million in capital during
10	the 2023 bridge (\$0.7 million) and 2024 test (\$0.2 million) periods for the
11	implementation of this NLP capability in the IVR.
12	
13	NLP in the IVR will allow customers to describe in their own words why they are
14	calling, and what it is they are trying to accomplish, providing a faster more direct
15	path through the IVR menu, and avoiding the frustration of today's fixed menu path
16	design that moves customers through the IVR based on business rules, logic, and
17	priorities. This frustration is evident by the $\sim 30\%$ of calls in 2022 ( $\sim 1,285,000$ )
18	made by customers that were routed through the "Universal" IVR queue, either
19	because the customer repeatedly hit "0" to bypass the menu, or because the
20	customer was not able to successfully navigate the menu and was connected to a
21	CR.
22	
23	NLP technologies will alleviate these issues by providing customers an easy way
24	to simply say why they are calling, with the NLP technology then routing the
25	customer to the most appropriate CR or IVR self-service solution. Additionally, if

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routed to an IVR self-service solution, NLP can be leveraged to increase the percent of customers whose completed transaction is completely contained in the IVR – for example, if a customer after completing their transaction indicates they want to speak to a CR, the NLP technology can ask the customer what additional information they need and link the customer to an automated chatbot that can answer their question.

7

8 While NLP will not completely eliminate the volume of Universal calls, the 9 Company is estimating, based on the current engagement of customers in the 10 available IVR self-service solutions, and the future opportunity to use NLP to 11 contain more completed customer transactions in the IVR, that NLP will result in a 12 decrease of ~123,000 calls annually by 2027, and provide an additional annualized 13 call volume savings of ~\$1.4 million. See Exhibit A-24 Schedule N9 Operational 14 Efficiencies Line No. 3. These call volume savings are in addition to the call 15 volume savings forecasted to be realized from the \$51.3 million portfolio of capital 16 projects discussed in Part 4 of my testimony, and are not part of the associated NPV 17 analysis. While the Company maintains that NLP will help reduce call volumes in 18 the manner described here, it will need to further evaluate the potential savings after 19 the technology is fully implemented.

20

#### 21

#### 5. <u>Line 54 – Secure Cloud Payment Provider Migration</u>

The Company will invest \$2.2 million in test period capital to implement a thirdparty secure cloud vendor that would work as an intermediary between DTE and our payment service provider to handle credit card payments. Today, when a customer pays their bill through the IVR or with a CR in the Contact Center using

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3

4

5

6

a credit card, the credit card information passes through DTE's systems on its way to our payment service provider for the actual payment handling. The customer's credit card information (credit card number, CSV code, expiration date, etc.) falls under Payment Card Industry Data Security Standard (PCI DSS) requirements which are a strict set of standards that must be followed when handling PCI data to maintain the ability to process payments.

7

8 Nearly all our IVR and Contact Center infrastructure falls under the PCI 9 requirements leading to increased maintenance, patching, and management work. 10 This means the Company has less flexibility in how our systems can be connected 11 to other data sources. Removing the credit card handling from our system and in 12 turn, the PCI requirements would reduce overhead and risk. This solution would 13 seamlessly integrate with both our IVR and CR workstreams to take over behind 14 the scenes when a customer needs to provide PCI information. The Secure Cloud 15 Solution would intercept all PCI data without any of it entering DTE's systems. 16 DTE would only receive enough masked/tokenized data to know that the data entry 17 was successful while our Payment Service Provider would receive the rest.

18

By investing in this project, we can forgo the near-annual capital investment to maintain PCI compliance. In 2023 and 2024, we are investing \$0.15 million in 2023 bridge period and \$0.18 million in test period capital in the PCI project (Line 7).

22

23 6. <u>Line 56 – Speech Analytics</u>

DTE invested \$1.4 million in 2021 historical period (\$0.2 million) and 2022 bridge period (\$1.2 million) capital to implement Speech Analytics in the voice channel,

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which will replace the currently manual process of having the CRs capture the reason for a customer's call using a customized "call wrap screen". While the call wrap screen provides more insight than simply monitoring and capturing customer IVR selections, it creates inefficiencies for CRs and is prone to the human errors that are inherently part of any manual process.

6

5 Speech Analytics software will automate the process of categorizing calls by 5 turning calls into text and leveraging advanced algorithms to classify calls into 5 more precise categories, including those calls that are currently classified as 5 "Other". This will allow the Company to quickly identify the specific items that 5 result in a call to the Contact Center. This insight will be important in the ongoing 5 design and implementation of new self-service technologies and to identify 5 opportunities to reduce repeat calls.

14

15 Additionally, Speech Analytics will eliminate the significant amount of time each 16 year that CRs spend at the end of a call populating the call wrap screen, which 17 averages 10 seconds per call. Unlike the Avaya Platform Upgrade (Line 25) 18 discussed above, these 10 seconds do not apply to every call handled in the Contact 19 Center. The reason for this is that today approximately 50% of calls are categorized 20 based on the creation of a transaction record (e.g., payment made, MIMO order 21 scheduled), and because CR compliance to perform Call Wrap to categorize the 22 remaining population of calls is approximately 60%, which means the additional 23 10 seconds per call only applies to about 20% of the total call volume. As such, 24 the Company is estimating that Speech Analytics will deliver annualized O&M

Line	M. J. HATSIOS
<u>No.</u>	
1	savings of \$146,000 by 2027.See Exhibit A-24 Schedule N9 Operational
2	Efficiencies Line No. 4.
3	
4	7. Line 58 – Workforce Automation for Contact Center
5	The Company is investing \$1.3 million in 2023 bridge period capital to implement
6	new automation and advanced analytics tools that can consume the status of CR
7	availability in real-time to take immediate, automated actions using artificial
8	intelligence directed by pre-defined business rules.
9	
10	Today, the Contact Center uses a combination of out-of-the-box and custom
11	reporting tools to monitor the status of the representatives and have created manual
12	processes to analyze the data and react to changing needs. The current manual
13	processes produce lag, thereby leaving room for improvements that can be captured
14	through real-time automation. These automated actions can support workforce
15	management activities such as optimization of off-phone development time and the
16	real-time monitoring of schedule adherence, capturing efficiencies based on the
17	state of the Contact Center at any given time (e.g., call volumes, service levels) that
18	can change rapidly from one minute to the next.
19	
20	These workforce automations will monitor in real-time CR productive status and
21	schedule adherence, and use this data to optimize off-phone activities and reduce
22	"shrinkage" (i.e., non-productive time) by 2%, which is equivalent to the reduction
23	of 16 full-time CRs (FTEs). In other words, workforce automation will allow for
24	the attrition of an additional 16 CRs starting in 2024, which will provide annualized

Line No.		M. J. HATSIOS U-21297
1		O&M savings of \$560,000 by 2027. See Exhibit A-24 Schedule N9 Operational
2		Efficiencies Line No. 5.
3		
4	Telep	hony System Efficiency
5	Q89.	Can you please describe what you mean by telephony system efficiency?
6	A89.	Yes. The efficiency with which the Company manages and maintains its telephony
7		systems, which includes the IVR, significantly impacts the accessibility of these
8		systems for our customers. This is especially true during times of increased
9		customer usage, such as during a significant customer outage event, and during the
10		application of required software patches and upgrades. To ensure high levels of
11		accessibility to the telephony systems, the Company is investing in projects that
12		will minimize the impact of software patches and upgrades, and provide
13		redundancy in these systems to handle excessively high customer usage, especially
14		instances when many customers are attempting to engage with the telephony
15		systems at the same time, which is not unusual during a significant storm event.
16		
17	Q90.	Can you describe those capital projects that are intended to improve the
18		accessibility of the Company's telephony systems?
19	A90.	Yes. To ensure high availability and accessibility of these systems, the Company is
20		investing \$5.1 million in historical, bridge, and test period capital in three projects
21		that will improve the accessibility of the Company's phone system and the IVR.
22		
23		I will describe each of these projects in the order in which they appear in Exhibit
24		A-12, Schedule B5.7.3:
25		

10.	
1	1. Line 18 – Migrate IVR to the Cloud
2	The Company will invest \$2.8 million in test period capital to move the Contact
3	Center's IVR system from an on-premise to a cloud-based solution. The IVR
4	platform consists of servers, databases, and software that currently reside on-
5	premise at DTE's Detroit and Ann Arbor data centers. This infrastructure requires
6	continuous maintenance, patching, and support to remain in working order. In
7	addition, this infrastructure is limited by what is physically in place.
8	
9	The migration of the IVR to a cloud-based solution will take the current system
10	components and migrate them to a virtualized, cloud solution. This cloud-solution
11	will provide dynamic scalability of system resources as load changes through the
12	day, week, and year, with increased redundancy across systems and regions as
13	needed. Additionally, all patching and updates will be handled behind the scenes
14	by the cloud provider with very little impact to the availability of the applications.
15	
16	2. <u>Line 41 – High Volume IVR Overflow</u>
17	The Company is investing \$0.6 million in 2022 and 2023 bridge (\$0.5 million) and
18	test (\$0.05 million) capital in this project to augment our IVR capacity by bringing
19	in a third-party IVR vendor to handle overflow calls when incoming calls surge
20	past the volume that our current infrastructure can support at any one time,
21	particularly during periods of a high volume of outages. While DTE's IVR
22	infrastructure is sized to handle call volumes during catastrophic (CAT) storms, if
23	the CAT storm is large enough and a large volume of calls come in during a short
24	period of time, our infrastructure is unable to handle all the concurrent calls.

1 In the summers of both 2021 and 2022, large storms caused hundreds of thousands 2 of power outages within minutes, resulting in a volume of calls from customers that 3 exceeded by 15X our fixed IVR capacity. Without the overflow IVR, customers 4 were routed directly to the call queues and required to wait for a lengthy amount of 5 time for the next available agent. The third-party IVR vendor would replicate our 6 critical storm functions within their own cloud environment and be on standby. 7 When DTE's IVR infrastructure reaches maximum capacity, we would transfer 8 calls to the vendor's IVR, reserving DTE capacity to handle calls where the 9 customer really needs to speak to a CR. Additionally, the third-party vendor would 10 be able to provide support in the event of a cyber-attack that brings down large portions of DTE's internal infrastructure and backup functions. This project 11 12 ensures that when customers need to reach us, they can.

13

14

Line

No.

#### 3. <u>Line 55 – SIP in Contact Center</u>

15 The Company is investing \$1.7 million in 2022 and 2023 bridge (\$1.4 million) and 16 2024 test (\$0.3 million) period capital in the implementation of Session Initiation 17 Protocol (SIP) phone line infrastructure to replace use of the outdated Time 18 Division Multiplexing (TDM) infrastructure. The current TDM infrastructure 19 supports only analog phone calls and requires a variety of physical components to 20 make it work. The capacity and reliability of this system are limited by the amount 21 and age of this physical equipment. TDM equipment is being phased out by the 22 industry, making it harder and more expensive to maintain.

23

A recent benchmarking survey conducted by DTE with 19 other peer utilities revealed that over 75% of them have already made the transition to SIP, with

several others in the process of making the transition. SIP utilizes digital signals
 for phone calls, allowing it to provide much higher throughput with very little
 physical infrastructure. Less infrastructure is easier to maintain and minimizes the
 risk of failure.

5

### 6 Field Operations Efficiency

- Q91. Can you describe those projects that create operational efficiencies and reduce
  the cost of field service work in the RM&P and Billing & Metering groups?
- 9 A91. Yes. The Company invested \$3.8 million in 2021 historical period (\$1.3 million)
  10 and 2022 bridge period (\$2.5 million) capital in two projects that will improve the
  11 efficiency and effectiveness with which metering, and collection field work is
  12 managed.
- 12 111
- I will describe each of these projects in the order in which they appear in Exhibit
   A-12, Schedule B5.7.3, according to their assigned line item in the exhibit:
- 16

17

13

# 1. Line 39 – Field Service Management (FSM) RMP

DTE invested \$2.7 million in 2021 historical period (\$1.2 million) and 2022 bridge period (\$1.5 million) capital, to upgrade the RMP collection and theft field order scheduling and dispatching functions to the ClickSoft cloud-based solution and was implemented in November 2022. This project was previously approved in DTE Electric MPSC Case No. U-20561 and is part of the broader enterprise-wide implementation of ClickSoft that is described in more detail in Witness Sharma's testimony, and which was originally planned to be implemented during 2020 but

Line <u>No.</u>	<b>M. J. HATSIOS</b> U-21297
1	was deferred as part of a reprioritization of investments in response to the impacts
2	of the COVID-19 pandemic.
3	
4	The ClickSoft solution for RM&P includes custom work optimization
5	configurations that will prioritize disconnects based on the amount and age of
6	arrears and optimize the assignment of work to support those priorities, resulting in
7	an annualized reduction of \$1 million in uncollectible expense across both DTE
8	Electric and DTE Gas, as well as \$34,000 in O&M savings from reduced system
9	errors, incorrect status and waste on field time execution of orders.
10	
11	2. Line 40 – Field Service Management (FSM) Billing & Metering
12	The Company invested \$1.0 million in 2021 historical period (\$0.14 million) and
13	2022 bridge period (\$0.9 million) capital to upgrade the special meter reading and
14	consecutively estimated meter read order scheduling and dispatching functions to
15	the ClickSoft cloud-based solution, the same solution I described in my testimony
16	related to the RM&P FSM project, and consistent with the broader enterprise-wide
17	transition to ClickSoft described in Witness Sharma's testimony.
18	
19	The ClickSoft solution for Meter Reading will integrate field order and dispatching
20	functions, providing for the automatic scheduling of work to field resources,
21	allowing field resources to receive work via an App, reducing system maintenance
22	activities, improving system availability, and providing enhancements to reporting.
23	It is expected that through these operational efficiencies, the Company will realize
24	an annualized reduction of 15% of total person-hours. The freed-up capacity will

Line <u>No.</u>		M. J. HATSIOS U-21297
1		be able to focus on the next set of prioritized work and result in \$45,000 in
2		annualized O&M savings.
3		
4	Back-	Office Efficiency
5	Q92.	Are there any other operational efficiencies or risks that can be mitigated with
6		capital investment in the Billing & Metering group?
7	A92.	Yes. The Company is investing \$0.9 million in bridge (\$0.7 million) and test (\$0.2
8		million) period capital in a project called Changing Bill Size on Line 29 of Exhibit
9		A-12 Schedule B5.7.3 to standardize the size of paper on which our customer bills
10		are printed. Currently, the paper on which we print our bills is a custom size and it
11		is only supplied by one supplier. By changing the bill size, we will be able to
12		mitigate any future risks in the paper supply used to print customer bills and better
13		able to take advantage of purchasing discounts among competing vendors.
14		
15		By changing of the bill size to a standard format, the Company will also be able to
16		utilize all three of our bill printing machines interchangeably. Currently, two
17		machines are dedicated to process ~80,000 bills daily and one that processes
18		correspondences (including Notice of Intent letters that provide our customers with
19		five days' notice before shut-off due to non-payment). When one of the two
20		dedicated bill printing machines goes down, there is only one machine left to print
21		the bills. With the change in the bill size, if one of the bill print machines goes
22		down, we will still have two other machines to print the bills and correspondences.
23		If our machines go down, it could delay getting our bills to our customers in a timely
24		manner. MPSC guidelines dictate that the customer should have a standard amount
25		of time to pay their bill (due date) based on when the bill was received.

No. 1 2 The change in bill size will also assist with our Disaster Recovery vendor in that 3 they will not have to take hours to set up their equipment if we experience a disaster. 4 With a more standard size bill, there would be no major equipment set-up time 5 needed. 6 7 **Q93.** What other opportunities for operational efficiency improvements has the 8 Company identified in the RM&P group? 9 A93. The Company invested \$0.8 million in historical (\$0.4 million) and test (\$0.4 10 million) period capital (Exhibit A-12, Schedule B5.7.3) to redesign CR&B 11 collection processes (Line 28) and to improve the management of instances of theft 12 and fraud (Line 19). I will discuss each of these projects here, beginning with the 13 redesign of the collection processes. 14 15 1. Line 28 – Business Rule Framework (BRF+) 16 The Company invested \$0.4 million in 2021 historical period capital to complete 17 the implementation of the BRF+ project, which was previously approved for \$0.8 18 million in test period capital in DTE Electric MPSC Case No. U-20561, with the 19 project expected to be completed in calendar year 2021. The Company spent a total 20 of \$3.0 million in 2020 capital and an additional \$0.44 million in capital to complete 21 and implement the project in 2021. 22 23 Prior to the completion of the BRF+ project, the SAP CR&B dunning (i.e., 24 collection management) solution was customized as part of the implementation of 25 the Company's SAP CR&B implementation to model existing DTE processes and

Line

1	legacy system methods. This resulted in errors in the treatment and flow of accounts
2	that should be subject to collection actions and created the need for a manual
3	process to ensure accounts move through the process in an accurate and timely
4	manner. A reversion to the standard SAP CR&B dunning rules engine ensures that
5	customer accounts are flowing properly through the dunning process, prevents
6	customers from accumulating large arrears balances, and provide customers with
7	the opportunity to seek assistance in a timelier manner.
8	
9	Overall, the BRF+ has provided total arrears reduction of \$6.1 million - \$3.8
10	million (2021) and an incremental \$2.3 million (2022), with an associated UCX
11	reduction of \$4.3 million – \$2.7 (2021) and an incremental \$1.6 million (2022).
12	Additionally, the annual costs associated with the manual labor that was required
13	to move accounts through the collection process has been reduced by \$300,000.
14	
15	2. Line 19 – Never Billed Accounts Due to Theft/Fraud
16	The Company is investing \$0.4 million in test period capital to create new
17	functionality in the core billing system that will provide a new screen for the RMP
18	Exceptions Team when a customer needs to be billed for theft, ID fraud or
19	bankruptcy and the normal billing process cannot be used.
20	
21	Currently, due to system limitations we are unable to generate a bill statement for
22	certain retroactive theft and identity fraud transactions when the customer no longer
23	resides at the address where the theft/fraud occurred. This means some customers
24	responsible for committing theft or fraud do not get billed for the charges they owe.
25	The current process adds a lump sum debit charge to the account, but that charge

1		sits on the account. Since no bill gets generated, the account will also never go
2		through the collection (SAP dunning) process. Since the billing system went live
3		in April 2017 through October 3, 2022, ~\$1.5 million in charges have accrued on
4		customer accounts that are stuck in the active arrears bucket. This new screen will
5		allow us to generate a bill containing all required information to be printed and
6		mailed to the customer responsible for the usage. If the bill remains unpaid, it will
7		then flow through the normal collection process.
8		
9	Syster	ms and IT Efficiency Projects
10	Q94.	Can you please describe those projects that are intended to maintain critical
11		legacy applications, expand the capacity and speed at which we develop and
12		implement customer IT enhancements, and reduce system downtime?
13	A94.	Yes. The Company is investing \$10.5 million in bridge and test period capital in
14		seven projects intended to: 1) Maintain and enhance our customer systems (CR&B
15		and Legacy applications), including the integration layer, to meet customer needs
16		and improve key customer transactions by implementing upgrades to back-end
17		processes; 2) Accelerate the development, Q/A, and testing of Customer IT
18		projects; and 3) Reduce the frequency and associated remediation and monitoring
19		costs of CR&B system outages. I will discuss these projects below in the order in
20		which they appear in Exhibit A-12, Schedule B5.7.3:
21		
22		1. Line 15 – Customer Legacy Applications Enhancement
23		The Company invested \$1.0 million in 2022 bridge period capital to enhance
24		customer legacy applications that were not retired or replaced as part of the
25		Company's CR&B SAP implementation in 2017, and that continue to support

Line	
<u>No.</u>	

1	important functions that allow us to serve our customers. The customer legacy
2	applications are non-SAP applications and include the Meter Data Management
3	(MDM) system, the Agency Web (AGW) application, and the Customer Outbound
4	Communications (COCM) system. On-going requests to address defects and make
5	minor enhancements are submitted by business users and prioritized against other
6	enhancement work. These enhancements to legacy applications are in response to
7	an identified emergent need, to address identified customer dissatisfiers, or to
8	maintain application compliance. This project provides funding to implement these
9	requested enhancements.
10	
11	2. <u>Line 16 – CR&amp;B Program Enhancement</u>
12	As seen in Table 2, \$0.4 million, of the total \$2.0 million in capital allocated to the
13	CR&B Program Enhancements project, funded a portion of the digital self-service
14	solution enhancements in 2022. The remaining \$1.6 million funded ~185 CR&B
15	system enhancements in 2022 for the continuous improvement of the five key
16	transactions, primarily MIMO (33% of 2022 volume), Collections (52% of 2022
17	volume), and Billing (15% of 2022 volume). Examples of the MIMO and
18	Collection enhancements are provided below.
19	

A total of 61 defects and enhancements were remediated and implemented in 2022 for the MIMO transaction, with some of the more significant examples included here, which consumed \$0.5 million of the available capital funding from this project:

25

Line <u>No.</u>	U-21297
1	• Updated the arrangement of CRM screens – providing a better call handling
2	experience and lower AHT.
3	• Created new notification templates for Force Move-Out customers -
4	represents $\sim 40\%$ of the move-out population and for which we have never
5	sent notifications.
6	• Updated the WISMO refresh rate so that the MIMO Order Tracker provides
7	near real-time data- reduced the refresh time from 15 minutes to 1 minute.
8	• Incorporated "clickable" links and information bubbles for the CR's
9	through the MIMO screens in CRM – reducing wait times and AHT.
10	• Established the ability to web register customers during the MIMO process
11	in CRM – at inception we observed a 200-300% daily increase.
12	• Enhanced the system so that one business partner at one premise was only
13	being provided one contract account - eliminated the risk of customer
14	receiving multiple billing statements.
15	
16	Collection
17	A total of 96 defects and enhancements were remediated and implemented in 2022
18	for the Collection transaction, with some of the more significant examples included
19	here, which consumed \$0.8 million of the available capital funding from this
20 21	project:
22	• Updated the 65 New Closed Loop emails and SMS were added to keep
23	customers informed of where they are in the Collection process, improving
24	our communications with the customer.

Line <u>No.</u>	U-21297
1	• Upgraded the Payment Kiosk to accept payments on customer accounts that
2	were disconnected for non-payment.
3	• Senior Flag automated to update when a customer reaches the age of 65.
4	This flag protects Seniors from disconnection due to non-payment as part
5	of the Winter Protection Plan (WPP) from November 1 to March 31.
6	• Refinements to optimize the SAP collection process (dunning process) to
7	reduce growth in arrears and potential write-offs and UCX.
8	
9	3. Line 17 – IT Application Environments Enhancement
10	There are multiple projects and upgrades occurring in the IVR system, in parallel
11	and in some cases simultaneously, and not enough environments to effectively
12	manage them. A second Quality Assurance ("Q/A") environment is needed to
13	accelerate the development and deployment of IVR applications. To satisfy this
14	need, the Company invested \$0.3 million in 2022 in a new QA environment.
15	
16	The new Q/A environment will provide DTE the ability to emulate the production
17	environment and call center routing, allowing development, deployment, and
18	regression testing for multiple, simultaneous projects. Completing projects on time
19	is a key part of any project plan and with the additional Q/A environment, projects
20	will not have to compete as frequently for Q/A time, potentially causing delays or
21	adjustments in their timelines and delivery dates. Competition for the Q/A space
22	can be especially hard on smaller projects when a larger project requires testing for
23	extended periods of time. The additional Q/A environment also provides more
24	flexibility for emergent or emergency requests that arise and need to be
25	accommodated into the overall deployment schedules.

1 2 In 2023 and 2024, the Company is investing \$0.7 million in 2023 bridge and 2024 3 test period capital for establishing additional environments for testing of new 4 enhancements in the N+1 and N+2 environments for the Service and Work Order 5 to Close Process and for the Customer Channels (i.e., Web and Mobile) projects. 6 Similar to the backup and backlog of IT projects waiting to go through Q/A, 7 multiple projects are developed at the same time and must queue up waiting to 8 complete regression testing in the single N environment that is connected to the 9 CR&B system for testing before they can be implemented into production. The 10 single testing environment delays delivery of projects and implementation of 11 improvements that benefit the customer. There is also an opportunity to reduce 12 server and operational costs through sharing the N+1 and N+2 environments for

14

15

13

#### 4. <u>Line 20 – Automated Application Monitoring Enhancement</u>

testing that can be captured with these investments.

16 In 2020, the Company invested \$0.7 million in capital to implement SAP Solution 17 Manager 7.2, which was described in Witness Sharma's testimony in MPSC Case 18 No. U-20836, and which included real-time monitoring of the CR&B applications. 19 Utilizing Solution Manager's monitoring capabilities is allowing the Company to 20 identify issues that are impacting the customer experience in real-time, which 21 allows for the more rapid identification, immediate escalation, and improved 22 responses to issues that would impact the customer. This is the type of monitoring 23 technology that enables the Company to proactively address issues before it impacts 24 availability of our systems to take calls or process self-service requests.

25

1	An additional \$0.7 million in bridge and test period capital was included in Witness
2	Sharma's testimony in U-20836 to provide funding for the on-going sustainment of
3	Solution Manager, while Witness Pizzuti's testimony in U-20836 included \$2.7
4	million in 2021 and 2022 bridge period, and 2023 test period, capital to expand the
5	solution and its capabilities. In the instant case and supported by my testimony,
6	we have updated our forecasted spend to \$2.3 million in the 2022 and 2023 bridge
7	period capital and \$0.9 million in test period capital, increasing the total capital to
8	\$3.2 million and shifting the start date of the project from 2021 to 2022.
9	
10	While we have implemented the Solution Manager application, the monitoring tool
11	can be expanded to provide broader coverage of business process applications and
12	the performance of the CR&B system. Expanded capabilities to be implemented
13	during the bridge and test periods include enabling 100+ interface monitoring (104
14	currently), adding 50 more jobs to job monitoring (58 jobs currently), 10 additional
15	user experience monitoring of key transactions (six jobs being monitored today),
16	10 more business process / intelligence monitoring (38 currently), and providing an
17	alert and sending a notification when computing power/performance is low for

18

The monitoring enhancements provided by this project also are expected to improve the SAP CR&B system's uptime by reducing the time to monitor unplanned system outages after they are restored. In 2022, there were 10 system outages that required on average 20 IT resources working eight hours each to restore the system and implement fixes after the system is back up. These same resources then spend a minimum of the next eight hours monitoring the system after the system is restored

supporting these processes.

1	to ensure it is stable. By implementing the additional monitoring features and
2	coverage of key processes, transactions and interfaces, the automated monitoring
3	based on rules and thresholds reduces valuable IT resource time to monitor the
4	system after restoring. Assuming the frequency of outages can be reduced from 10
5	to 3 by 2027 with the implementation of the Transform and Modernize PO
6	Architecture project discussed later in this section, the savings from automating this
7	monitoring process will generate IT efficiencies and provide avoided O&M costs
8	of \$112,000 between 2025- 2027. See Exhibit A-24 Schedule N9 Lines 10 and 16.
9	
10	5. Line 22 – Supporting Capabilities Test Data and Test Data Management
11	Currently, the CR&B application team must manually create data in support of the
12	testing of enhancements and new solutions in the Customer Service IT Portfolio.
13	The manual process is cumbersome, time consuming, error-prone, and can result in
14	excessive levels of retesting. To eliminate these issues, the Company invested \$1.2
15	million in 2022 bridge period capital to establish a process to generate automated
16	test data and test scripts.
17	
18	The additional testing functionality and enhanced testing environment provided by
19	this project will allow the Company to bring current its testing processes and
20	practices by increasing the efficiency through providing the capacity and ability to
21	perform testing of newly developed IT projects without interrupting other projects
22	that are already in the testing environment. This application further automates our
23	ability to perform regression testing of all systems and software that could be
24	affected by introducing the new IT project into the production environment and
25	ensuring there are not adverse effects. We estimate this new capability will save

Line No.

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600 hours of IT support resources' time per year to perform regression testing prior to the implementation of a project into the production environment; this equates to ~\$60,000 in annualized O&M savings.

5 While not directly connected with improving electric reliability, all IT investments, 6 including those that support DTE Electric's ability to deliver better electric 7 reliability, safety or more accurate bills, must be tested. The speed and 8 comprehensiveness of the testing will also allow us to be more dependable. For 9 example, the Company's CR&B system must be able to handle a significant influx 10 of customer calls or customer outage reporting on the Web or in our mobile app, 11 often simultaneously, during catastrophic storms. In these moments of service, the 12 CR&B and related systems' availability and performance are critical. This project 13 will enable us to scale up our testing to simulate a catastrophic storm with a large 14 population of customers. Moreover, this application improves the effectiveness of 15 our testing process by providing the ability to save existing and incorporate new 16 testing features and testing scenarios, which provides the necessary data for 17 continuous improvement.

18

#### 19 6. <u>Line 23 – Transform and Modernize PO Architecture</u>

The Company will invest \$1.0 million in 2024 test period capital to transform and modernize the Process Orchestration (PO) architecture to alleviate system bottlenecks due to network traffic and growing functionalities in the CR&B system. As we enable more capabilities in our customer channels and in the CR&B system, this creates additional stress and burden for the PO to ensure increasingly complex jobs and functions perform as expected. During periods of high traffic such as

1 during a storm or in the fall with the influx of college move-ins, our transactional 2 system and our digital channels must scale up to handle the additional workload or 3 risk an unplanned system outage. By upgrading the PO to a more robust 4 architecture, we will be able to reduce unplanned system outages which disrupt our 5 ability to serve customers either digitally or through our contact center. While the 6 system is typically back up in  $\sim$ 3 hours during an unplanned outage, it takes longer, 7 at least eight hours, to identify the root cause and implement a longer-term fix so 8 the system is stable. In 2022, there were 10 unplanned system outages. Estimating 9 that each outage requires at least 20 IT resources eight hours to fully remediate the 10 cause of the unplanned outage, we incurred an expense of \$16,000 per outage and 11 \$160,000 annually. By reducing unplanned system outages from 10 to three per 12 year (2027 target), the Company can capture IT efficiencies and avoid \$112,000 in 13 unplanned outage costs between 2025-2027.

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There is also the cost of CRs who are waiting for the system to be restored to consider. It takes ~3 hours for the system to come back up. Assuming unplanned system outages reduce from 10 to 3 by 2027, by multiplying this idle / wait time by the average number of CRs by year between 2025 and 2027 and the hourly labor cost of a CR, this project can reduce the O&M cost of CR wait time by \$290,000. For project benefits, see Exhibit A-24 Schedule N9 Line Nos. 7-9 and Line Nos.13 and 15 for the amount of IT cost avoidance and Customer Service O&M savings.

22

#### 23 7. <u>Line 50 – Platform Integration Component</u>

The Company invested \$1.6 million in 2022 bridge capital in the Platform Integration
Component project to enhance the integration between the SAP systems (in the back-

1	end) and many of our Customer Service IT projects that provide an enhanced or new
2	customer experience in our digital channels (i.e., front-end, and customer-facing
3	system or technology.) All front-end customer experiences where data is collected,
4	including interacting with a CR in our Contact Center, require integration and a
5	connection to the back-end SAP customer systems (e.g., SAP Customer Relationship
6	Management (CRM) system and SAP back end I-SU system) where the data is
7	processed and stored.
8	
9	This SAP application remains the best alternative when evaluating integration solutions
10	with other SAP systems since the products were designed to work together in a
11	seamless manner. Migration of functionality and capability from disparate legacy
12	systems or applications to a single SAP platform allows information from our
13	operations and other areas to flow more smoothly from back-end systems to front-end
14	systems that directly serve the customer.
15	
16	To ensure that the Customer Technology Platform systems are tightly integrated to
17	handle the much-anticipated volume of inquiries from the implementation of TOD
18	rates in 2023, ~1.0 million of the \$1.6 million invested to fund this project was used
19	to fund integration layer work related to the implementation of the TOD rates. The
20	funding enables customers to evaluate and enroll into different rate options using
21	the Web, including calculating the bill impact, and using the bill analyzer and bill
22	simulator. This adds the capacity for the Company to serve a larger volume of
23	customers via the Web than could be handled by the Contact Center in TOD billing
24	inquiries prior to or after the implementation of the TOD project implementation.
25	

1	<u>Part (</u>	5. Projects that Enhance Customer Interactions
2	Q95.	Can you describe the Company's rationale for investing capital in projects
3		that will enable "Enhanced Customer Interactions"?
4	A95.	The Company's strategy to enhance customer interactions is simple – improve the
5		customer experience and the effectiveness and efficiency with which the Company
6		manages customer interactions, by prudently investing in capital projects that
7		enable end-to-end monitoring of customer interactions, that provide customers and
8		employees full transparency into the status of these interactions, and that improve
9		the quality of the data and information provided to customers during these
10		interactions.
11		
12	Q96.	How much is the Company investing in projects that enable "Enhanced
13		Customer Interactions"?
14	A96.	The Company is investing a total of \$46.1 million in historical (\$4.8 million),
15		bridge (\$28.5 million), and test (\$12.8 million) period capital in a portfolio of
16		projects that will modify the Customer Technology Platform to enable the delivery
17		of "Enhanced Customer Interactions", which will be accomplished through:
18		
19		• The creation of systems that enable the end-to-end monitoring of customer
20		interactions, including the development of internal dashboards to improve
21		the effectiveness with which customer interactions are managed.
22		• Providing customers, and DTE employees, visibility and transparency into
23		the status of customer interactions, so that customers "see what the Company
24		sees".
<u>No.</u>		
------------	--	
1	• The implementation of an enhanced communication platform that is more	
2	efficient, flexible, and scalable than the existing platforms.	
3	• The enhancement of existing, and the creation of new, customer notifications	
4	that are accurate, timely, and relevant to the customer's interaction,	
5	including those related to customer Outage status updates and restoration	
6	estimates.	
7	• The gathering of real-time voice of the customer feedback on the quality of	
8	their interaction with the Company, providing insight into customer	
9	dissatisfiers and enabling faster resolution of customer concerns.	
10		
11	Q97. In which of the Company's sponsored capital exhibits is the \$46.1 million in	
12	capital reflected?	
13	A97. The \$46.1 million in total capital is included in eight projects, six of which are	
14	included in Exhibit A-12, Schedule B5.7.3, which I am sponsoring, and two of	
15	which are included in Exhibit A-12, Schedule B5.4 Tech, which is sponsored by	
16	Witness' Hill, Andahazy, Smith, and Hartwick.	
17		
18	Exhibit A-12, Schedule B5.7.3	
19	1. Line 21 – SAP Cloud Platform – Foundational Additions (\$0.4 million)	
20	2. Line 32 – Customer Closed Loop Development (\$3.8 million)	
21	3. Line 33 – Customer Service Communications (\$3.4 million)	
22	4. Line 34 – Customer Sales and Service (\$7.3 million)	
23	5. Line 38 – EFC – Outage Status (\$19.9 million)	
24	6. Line 53 – Qualtrics Expansion (\$0.5 million)	
25		

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	M. J. HATSIOS U-21297
	Exhibit A-12, Schedule B5.4, page 12, Technology and Automation
	1. Line 36 – Other Modernize Grid Management (\$4.1 million)
	2. Line 38 – Operational Technology and EFC (\$6.7 million)
	The \$3.8 million in capital for the Customer Closed Loop Development project, is
	net of the \$0.5 million that funded the system changes required to implement the
	Collection order tracker, as previously described in my testimony. The \$19.9
	million in capital for the EFC – Outage Status project, is net of the \$5.3 million that
	was used to fund the 2022 Outage digital self-service enhancements, as previously
	described in Part 4 of my testimony.
	Additionally, the \$4.1 million in capital provided by the Other Modernize Grid
	Management project, and the \$6.7 million in capital provided by the Operational
	Technology and EFC project, reflect the portion of the total capital for these
	projects, in Exhibit A-12, Schedule B5.4, page 12, that is allocated to the
	Company's EFC – Outage Status initiative, which I will discuss in a subsequent
	section of this part of my testimony.
Q98.	Which of the projects that enable "Enhanced Customer Interactions" would
	you like to describe first?
A98.	I'd like to discuss the \$3.8 million in historical (\$2.3 million), bridge (\$1.7 million)
	and test (\$0.3 million) period capital allocated to the Customer Closed Loop
	Development project, as it represents the framework for how the Company is
	enhancing the design of its customer interactions.
	<b>Q98.</b> A98.

1	Q99.	Can you describe the Company's closed loop "framework" and how it is
2		applying it to customer interactions?
3	A99.	The DTE Closed Loop framework, which defines the manner in which the
4		Company is designing and managing its five key transactions, was fully described
5		and detailed in Witness Pizzuti's testimony in DTE Electric Rate Case No. U-
6		20836. Witness Pizzuti's testimony provided the support for the Company's
7		requested recovery of \$8.5 million in historical, bridge, and test period capital (U-
8		20836, Exhibit A-12, Schedule B5.7.3, Line 38) to fund the Customer Closed Loop
9		Development project, for which the Company subsequently received approval of
10		\$7.9 million of the requested capital in the Commission's November 18, 2022, U-
11		20836 Order.
12		
13	Q100.	Can you provide in this instant case, an overview of how the Company's
14		Closed Loop framework improves customer interactions?
15	A100.	Yes. Foundational to the application of the Company's Closed Loop framework,
16		was to create the ability for the Company to track customer requests related to the
17		five key transactions from inception all the way through to the fulfillment of that
18		transaction. To accomplish this, the Company developed the "Where is My Order"
19		(WISMO) application, which I referenced in Part 4 of my testimony in the instant
20		case as part of my discussion of the Collection online order tracker.
21		
22		The WISMO application, which is reflected in Figure 3 as Service Order
23		Management, integrated together several customer and workforce management
24		technology platforms - Channels, Maximo, Service Suite/ClickSoft, CRM, and
25		CR&B - to build a Service Order Management system that leverages the creation

# Line <u>No.</u>

1 of a unique order tracking number for customer transactions. This WISMO order 2 number is used to track customer transactions over the entire "customer order 3 lifecycle", and to present the status of these orders to customers in the self-service 4 channels, and to CRs in the CRM system, and to trigger status updates to customers 5 in the form of SMS (text) and email messages. 6 7 For example, during instances in which the fulfillment of a customer order requires 8 multiple steps and handoffs between organizations (e.g., Contact Center and the 9 back-office and field operations) and that requires action on the part of the customer 10 (e.g., the submitting of documents) to complete the order, the WISMO application 11 ensures that: 12 13 The data related to each order is captured and updated at appropriate ٠ 14 intervals in the customer order lifecycle. 15 The data is made visible and presented to customers and employees in the ٠ 16 self-service channels and in the Company's internal systems. 17 ٠ Relevant and accurate status updates are provided to customers in their 18 preferred communication method (i.e., SMS/email). 19 • Customers are provided follow-up information and instructions on how to 20 complete tasks that are needed for them to complete their transaction. 21 Enables the development of internal dashboards that can be used to monitor • 22 customer orders in real-time, and that can be used as a service recovery tool 23 for customers that are "stuck" somewhere in the order lifecycle. 24

1	Prior to the creation of the WISMO application, the Company's customer and work
2	management platforms provided binary and very limited status updates for
3	customers – e.g., "your payment is due", "your payment has been received", "your
4	MIMO order is scheduled", "your MIMO order is complete" - with no effective
5	way for the Company or its employees to monitor or manage orders as they
6	progressed through the customer order lifecycle.
7	
8	Q101. To which of the five key transactions has it applied its Closed Loop
9	framework?
10	A101. The Company has leveraged the WISMO application to apply its Closed Loop
11	framework to the MIMO, Collection, and Outage transactions. The application of
12	the Closed Loop framework to the MIMO and Collection transactions was
13	discussed in detail in Witness Pizzuti's testimony in U-20836, while the application
14	of WISMO and the Closed Loop framework to the Outage transaction will be
15	discussed in my testimony as part of my discussion of the EFC - Outage Status
16	initiative.
17	
18	Q102. How has the implementation of these Closed Loop enhancements improved
19	the MIMO and Collection experience for customers?
20	A102. For both the MIMO and Collection transactions the Company has enhanced
21	existing, and created new, notifications for customers that are providing them
22	transparency and insight into the status of their order, and that provides them links
23	to relevant information (e.g., order status, document submission status, energy
24	assistance information, or payment options). Additionally, the Company has
25	created an internal dashboard that is used to track the status of each MIMO and

Line
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1	Collection transaction, along with all of the customer notifications. This dashboard
2	is monitored daily and used to identify instances where a customer order is "stuck"
3	and requires intervention to ensure the customer is made aware of any changes in
4	the status of their order and the Company fulfills its commitments.
5	
6	These enhancements have been well received by customers, who are reporting
7	higher levels of MIMO and Collection First Contact Resolution (FCR) and
8	satisfaction, as measured by our Transactional Satisfaction (TSAT) survey:
9	
10	1. MIMO FCR is at 91% (2022) vs. a target of 88%, the second highest of the
11	five key transactions (2022 Payment FCR is 95%).
12	2. MIMO TSAT is at 70 (2022) vs. a target of 64, the highest of the five key
13	transactions (next highest is Payments with a TSAT of 53)
14	3. Collection FCR has increased from 72% in 2020 to 80% in 2022.
15	4. Collection TSAT has increased from 30 in 2021 to 41 in 2022.
16	
17	Another measure that the Company uses to assess the experience of Collection
18	customers, is the percent of complaints that are from customers who are restored
19	after being shut-off for nonpayment, which has decreased from 0.53% in 2019 to
20	0.25% in 2022 as a result of the Company's Collection Closed Loop initiatives.
21	
22	Q103. Can you please next describe the scope and purpose of the Company's EFC –
23	Outage Status initiative?
24	A103. Yes. The frequency and impact of the 2021 storms (Figure 17) caused a great deal
25	of frustration for customers who lost power, for the Company's employees engaged





5

7 Customer feedback during this period of heavy storm activity made it clear that 8 while customers are frustrated when they lose power, the most significant source 9 of that frustration is not necessarily due to the loss of power, but rather from 10 unreliable restoration estimates, a lack of relevant and timely information from the 11 Company, and the inaccurate notification of their restoration status (i.e., "power-12 on" when it is not), all of which erodes customer trust and confidence and 13 significantly increases their level of frustration.

14

15 To address these customer dissatisfiers, and to provide customers the level of 16 service they expect and deserve, the Company in 2021 launched the EFC – Outage 17 Status initiative, which consists of a fundamental redesign of all the processes, core



systems, sub-systems, and system integrations that work together to monitor and
 manage customer outage communications, with the goal of significantly improving
 the customer Outage experience, especially regarding the quality of the information
 provided to customers during an outage.

As part of their assessment of the customer Outage experience, the EFC – Outage Status project team identified seven Moments-that-Matter (MTM) most to the customer during an outage. These MTM represent the different stages of an outage during which a customer would expect, and benefit most from, accurate, timely, and relevant information related to that outage (Figure 18).

11

10

5

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14 Simply put, customers want to know if a storm is coming and if that storm has the 15 potential to cause a loss of power so that they can proactively prepare (MTM #1), 16 and if they lose power, customers want timely and accurate updates as to when their 17 power is expected to be restored, so that they can adjust their plans accordingly 18 (MTM #2-6), and finally, customers who are not home when the power goes out,

Line No.	<b>M. J. HATSIOS</b> U-21297
1	or who have found alternative accommodations, want to know as soon as possible
2	that their power has been restored so that they can safely return home (MTM #7).
3	
4	Q104. What opportunities for improvement did the Company identify in its
5	assessment of the current Outage experience provided to its customers?
6	A104. The Company identified a number of opportunities for improvement across the
7	Outage experience MTM during the 2021 storms, which were substantiated by the
8	feedback received from customers, and which I've summarized here:
9	
10	• Customers received inaccurate power restoration communications,
11	which were triggered by job closures/cancellations instead of real-time
12	AMI data.
13	• Customers were required to resubmit outage reports which were not
14	properly detected for "trouble-behind-trouble" (TBT), which describes
15	customers on circuits that were restored but who are still without power
16	for some other reason.
17	• Customers went long periods of time without estimated restoration times
18	and without relevant information on storm restoration efforts and
19	progress.
20	• Customers received multiple inaccurate estimated restoration times.
21	• Customers were not receiving notifications (SMS/email) as expected.
22	
23	Q105. What fundamental changes did the Company determine were necessary to
24	improve the quality of the information provided to customers during an
25	Outage?

1	A105.	In simple terms, the Company determined that it needed to transition from a "work-
2		based" power status system to a "premise-based" system, with premise being the
3		Company's term for a customer's home or business location. The Company's
4		"work-based" system aggregates outage data from the AMI network, input from
5		field crews, and customer calls, and. couples this data with the electrical system
6		equipment hierarchy to determine outages at a circuit level. The system does not
7		focus on tracking and monitoring individual customer outages. Creation of a
8		"premise-based" system allows the Company to leverage its AMI infrastructure to
9		monitor individual premise outage data and restoration status, and provide power
10		status and notifications at the customer level. This significantly enhances the
11		relevance and quality of the data provided to customers, and improves the customer
12		Outage experience.
13		
13 14	Q106.	What technical components are required to create premise-based Outage
13 14 15	Q106.	What technical components are required to create premise-based Outage management?
13 14 15 16	<b>Q106.</b> A106.	What technical components are required to create premise-based Outage management? There are six technical components that form the landscape of systems necessary
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> </ol>	<b>Q106.</b> A106.	What technical components are required to create premise-based Outage management? There are six technical components that form the landscape of systems necessary to create the Company's premise-based system, some that already exist, some that
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> </ol>	<b>Q106.</b> A106.	What technical components are required to create premise-based Outage management? There are six technical components that form the landscape of systems necessary to create the Company's premise-based system, some that already exist, some that exist but need to be modified, and some that are completely new:
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> </ol>	<b>Q106.</b> A106.	What technical components are required to create premise-based Outage management? There are six technical components that form the landscape of systems necessary to create the Company's premise-based system, some that already exist, some that exist but need to be modified, and some that are completely new:
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> </ol>	<b>Q106.</b> A106.	What technical components are required to create premise-based Outage management? There are six technical components that form the landscape of systems necessary to create the Company's premise-based system, some that already exist, some that exist but need to be modified, and some that are completely new: <ol> <li>Outage Management System (OMS) – Existing system that processes</li> </ol>
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> </ol>	<b>Q106.</b> A106.	<ul> <li>What technical components are required to create premise-based Outage management?</li> <li>There are six technical components that form the landscape of systems necessary to create the Company's premise-based system, some that already exist, some that exist but need to be modified, and some that are completely new:</li> <li>1. Outage Management System (OMS) – Existing system that processes outages with work-based calculations, using field crew job and equipment</li> </ul>
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> </ol>	<b>Q106.</b> A106.	<ul> <li>What technical components are required to create premise-based Outage management?</li> <li>There are six technical components that form the landscape of systems necessary to create the Company's premise-based system, some that already exist, some that exist but need to be modified, and some that are completely new:</li> <li>1. Outage Management System (OMS) – Existing system that processes outages with work-based calculations, using field crew job and equipment data.</li> </ul>
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>23</li> </ol>	<b>Q106.</b> A106.	<ul> <li>What technical components are required to create premise-based Outage management?</li> <li>There are six technical components that form the landscape of systems necessary to create the Company's premise-based system, some that already exist, some that exist but need to be modified, and some that are completely new:</li> <li>1. Outage Management System (OMS) – Existing system that processes outages with work-based calculations, using field crew job and equipment data.</li> <li>2. AMI – The Company's Automated Metering Infrastructure (AMI), which</li> </ul>

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Line <u>No.</u>	U-21297
1	Restoration Notifications (PRNs) into PPS for processing premise-based
2	calculations.
3	3. ESRI's ArcGIS – Maintains the equipment hierarchy for the electric grid.
4	The OMS system uses the hierarchy to map equipment outages to the
5	customers attached to that equipment.
6	4. Event Hub – A new system that streams the outage events from OMS into
7	the new PPS system.
8	5. Premise Power Status (PPS) - A new system that translates work-based
9	outage information from OMS, and the AMI meter data, into premise-based
10	outage information.
11	6. "Where is My Orders" (WISMO) – The Company's order tracking system,
12	which for Outages, integrates information from PPS to allow for tracking of
13	individual customer outages, and to trigger the appropriate notifications to
14	customers.
15	
16	A view of the different systems that together provide the new premise-based
17	architecture is provided in Figure 19.
18	





## Figure 19Premise-Based Power Status System Architecture

2

# Q107. Can you expand on the scope of work that was required to create the premisebased system architecture shown in Figure 19?

5 A107. Yes. The existing OMS, ArcGIS, and AMI systems required new interfaces to be 6 built to connect and transfer data to Event Hub. Event Hub streams this data into 7 the new PPS solution, which uses the data from Event Hub, including scheduled 8 interrogations for all AMI meters, automated voltage reads that are triggered after 9 field-work completes, and one-off voltage reads for single customer outage status 10 and restoration checks, to determine the meter status for each individual customer 11 premise. Data from PPS is then streamed to the WISMO order tracker, which 12 aggregates the PPS data to monitor and track the status of customer outages at the 13 premise level, to determine which notifications to send to which customers 14 depending on the status of their individual situation, and to present the most current

M. J. HATS	IOS
U-2.	.297
and accurate outage data in the served (CRM) and digital self-service chan	nels.
The end result is that customers are provided the most accurate premise-b	ased
outage status and restoration information possible.	
Q108. How much capital has the Company allocated to its EFC – Outage St	atus
initiative?	
A108. There are three capital projects associated with the Company's EFC - Ou	tage
Status initiative:	
1. EFC – Outage Status (Exhibit A-12, Schedule B5.7.3, Line No. 38)	
2. Other Modernize Grid Management (Exhibit A-12, Schedule B5.4, page	e 12,
Line No. 36)	
3. Operational Technology and EFC (Exhibit A-12, Schedule B5.4, page	: 12,
Line No. 38)	
Together these three projects provide \$36.0 million in historical (\$2.4 mill	ion),
bridge (\$28.8 million), and test (\$4.8 million) period capital required to make	e the
necessary modifications to the Customer Technology Platform (Figure 3) to sup	port
the EFC – Outage Status initiative.	
Q109. How was the \$36.0 million in total capital allocated across the sys	tem
architecture you described in Figure 19?	
A109. A total of \$10.8 million in historical (\$2.4 million) and bridge (\$8.4 million) pe	riod
capital was invested in creating the new Event Hub and PPS systems, and to cr	eate
the system interfaces necessary to connect OMS, ArcGIS, and AMI to Event	Hub

Line <u>No.</u>	U-21297
1	for the streaming of data into PPS. This capital is reflected in the total capital
2	amounts shown in Exhibit A-12, Schedule B5.4, page 12, Line No. 36 and 38.
3	
4	A total of \$9.8 million in 2022 bridge period capital was allocated to 1) the creation
5	of the WISMO Outage order tracker, 2) the enhancement of the served (CRM) and
6	self-service channels to consume the premise-based WISMO Outage data, 3) the
7	creation of enhanced customer Outage notifications, and 4) the creation of new
8	internal end-to-end Outage monitoring and reporting tools. This capital is
9	reflected in the total capital shown in Exhibit A-12, Schedule B5.7.3, Line No. 38.
10	
11	Q110. How is the remainder of the \$15.4 million in capital being allocated to support
12	the EFC – Outage Status initiative?
13	A110. As previously discussed in my testimony, $5.3$ million in capital from the EFC –
14	Outage Status project (Exhibit A-12, Schedule B5.7.3, Line No. 38) was allocated
15	to the funding of the 2022 Outage Web self-service enhancements described in Part
16	4 of my testimony. The remaining \$10.1 million in bridge (\$5.3 million) and test
17	(\$4.8 million) period capital, is allocated to the following scope of work:
18	
19	1. Launch of new Outage map – The design and implementation of the new
20	industry standard Kubra Outage map solution, which is scheduled to go
21	live in 2023 concurrent with the new ADMS system.
22	2. Integration of PPS with ADMS – The launch of ADMS will change the
23	way the premise-based systems receive data. The Company must ensure
24	that PPS is properly integrated with ADMS to maintain the quality of the

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outage data presented to customers in the digital self-service	channels
and in the Outage customer notifications.	
3. Outage Map Integration – Integration of the new Outage n	nap with
ADMS and with WISMO to maintain the quality of the ou	tage data
presented to customers on the map (ADMS), and to enh	nance the
messaging for customers using the map to be more relevan	t to their
outage (WISMO).	
4. Improved Restoration Estimate Timeliness and Accuracy-Sig	nificantly
enhancing the timeliness and accuracy of customer storm re-	estoration
estimates, with the goal of providing a single and accurate esti-	mate. To
that end, the Company is investing in a machine learning mode	l that will
use historical data to generate estimates for customers durin	g storms,
which is consistent with what many peer utilities have done to	) improve
the accuracy of the restoration estimates for their customers.	
5. Enhanced Address Lookup - The addition of smart addres	ss search
capabilities that will allow customers to quickly and accurately	find their
address when submitting an outage event, which can be a	barrier to
reporting an outage for some customers.	
6. Proactive "Status First" Outage Notifications- Leverage	the new
premise-based system to proactively inform customers that the	Company
is aware of their outage. This includes messaging customers	s who are
using a digital self-service channel to report their outage	that the
Company is aware they are without power.	
7. Notifications for Customers who are "Likely Out" – The Comp	pany uses
various data points (e.g., AMI, equipment status, custome	r Outage

1 reports, etc.) to predict when a whole circuit or area is without power. 2 While the new premise-based system uses customer AMI data to 3 determine if a customer is without power, the AMI data is not available 4 100% of the time for 100% of the impacted customers. To proactively 5 reach out to customers who are very "likely out", the Company is developing the ability to trigger notifications to these customers to let 6 7 them know that the region in which the live has been impacted by a 8 storm, how many customers are impacted, and that it is believed that they 9 are without power as well, and provide these customers a method (e.g. 10 two-way texting) to confirm their power status.

8. Police, Fire, and Municipality Outage Reporting – WISMO does not
 currently track outages reported by Police, Fire, or Municipalities.
 Instead, these outages are reported by CRs in CRM. Transitioning from
 CRM to WISMO will provide the same proactive monitoring, tracking,
 and messaging for these outages as for those reported by other
 customers.

- Enhancement of Planned Outage Communications The Company will
   leverage its premise-based system to improve the timeliness and quality
   of customer notifications for planned Outages.
- 20 10. Customer Preference Management Leverage the new Customer
   21 Communications Platform, which I discuss in a subsequent section of
   22 this part of my testimony, to improve the capturing and use of customers
   23 preferred service and communication channels during an outage.
- 24

Line

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ine U-2129	)S 97
1 A detailed line-item assessment of the allocation of the total \$36.0 million in EF	FC
2 – Outage Status initiative capital, for which the Company is seeking recovery in the	he
3 instant case, is provided in Exhibit A-24, Schedule N10.	
4	
5 Q111. What are the forecasted improvements in Outage metrics from the \$36	<b>5.0</b>
6 million capital investment in the EFC – Outage Status initiative?	
7 A111. In addition to its contribution to the Outage call volume reductions described in n	ny
8 Part 4 of my testimony, for which the EFC – Outage Status project contributed \$5	5.3
9 million in capital, the Company has identified three key areas of improvement th	ıat
10 will be enabled by the total \$36.0 million in capital investments:	
11	
12 1. <u>Power Restoration Accuracy</u>	
• Goal – Improve the accuracy & timeliness of the customer's power state	us
14 when they are restored, which is communicated and displayed to the	he
15 customer on all self-serve and serve channels.	
• Pre-EFC Performance – Prior to the implementation of EFC, the customer	c's
17 power status was tied to the job status, which was overall 94% accurat	te,
18 with a range between 80% to 94% during high impact and storm day	ys.
19 During one of our largest storms in 2021, approximately 40,000 custome	ers
20 were impacted with an inaccurate power restoration status, where the	he
21 Company believed the customer's power was restored (i.e., TBT), which	ch
22 was what was communicated on all our channels to the customer, however	er,
23 the customer was in fact, not restored.	
• 2022 Performance – With the implementation of EFC, where the customer	ť's
25 power status is based on AMI data, the Company has consistently achieve	ed

1	a 99% accuracy rate for the customer's power status. However, with the use
2	of AMI data, timeliness of accurately identifying the customer's power
3	status when they are restored became an issue. While we were able to
4	accurately identify 62% of customer's power status within 30 minutes, we
5	had 10% of customers that we obtained their power status 6+ hours after
6	they were restored, with the remaining 28% identified within 30 minutes
7	and 6 hours of actual power restoration.
8	• 2023 Forecast – The Company is forecasting that the EFC enhancements
9	described in my testimony will maintain Power Restoration Accuracy at
10	99%, while improving the timeliness of accurately identifying the
11	customer's power status to 10 minutes or less.
12	• Long-Term Target – To maintain a Power Restoration Accuracy of 99%
13	and improve timeliness to identify the customer's power status to 5 minutes
14	or less.
15	
16	2. <u>First Estimate Accuracy</u>
17	• Goal – Improve the accuracy of the first Estimate Restoration Time (ERT)
18	that is delivered to the customer and the timeliness to deliver that ERT after
19	the customer. First Estimate Accuracy measures the percent of customers
20	that we received a single accurate estimated restoration time (ETR).
21	• Pre-EFC Performance – The Company achieved 35% First Estimate
22	Accuracy during storm.
23	• 2022 Performance – The Company achieved 42% First Estimate Accuracy
24	during storm and delivered the first ETR to the customer within 24-48 hours
25	after the storm weather cleared.

Line

No.

Line <u>No.</u>	U-21297
1	• 2023 Forecast – The Company is forecasting 80% First Estimate Accuracy
2	for non-catastrophic storms, and 55% for catastrophic storms, to be
3	delivered to the customer within 4-hours of storm weather clearing.
4	• Long-Term Target – The Company is targeting 95% First Estimate
5	Accuracy during all storms, to be delivered to the customer within 4 hours
6	of the customer's power lost.
7	
8	3. <u>Outage Notification Delivery</u>
9	• Goal – Increase the percentage of customers who receive outage status
10	notifications (SMS/email), which includes notifications for power is out,
11	estimated restoration times (ETR), and power is restored.
12	• Pre-EFC Performance – 45% of customers with reported outages
13	successfully received the expected outage status notifications.
14	• 2022 Performance - Implemented EFC enhancements increased the
15	percentage of customer with reported outages successfully receiving outage
16	status notifications to 70%.
17	• 2023 Forecast – The Company is forecasting to increase the percent of
18	customers with reported outages successfully receiving the expected outage
19	status notifications to 88%.
20	• Long-Term Target – The Company is targeting to increase the percent of
21	customers with reported outages successfully receiving outage status
22	notifications to 95%.
23	

			ľ	M. J. HATSIOS
Line <u>No.</u>				U-21297
1	Q112. Can you provid	le an overview of how t	the Company has enhar	nced the Outage
2	notifications for	• customers through its	capital investment in th	e EFC – Outage
3	Status initiative	?		
4	A112. Yes. Figure 2	20 provides a summa	ry of the specific Out	age notification
5	enhancements at	each of the Outage MT	М.	
6				
7	Figure 20	EFC – Outage Statu	s Notification Enhancen	nents
	Pre-Storm During Storm	Impact Assessment	Estimate Process	Restoration Complete
	"We anticipate severe weather and potential outages in Southeast area"	"Our crews are <b>assessing damage</b> caused by severe weather once we assess the damage, we will provide an estimated time of restoration"	"Your estimated restoration is Sat, Jun 25. Our crews are working diligently to restore your power"	"We have restored power to your property. If you're still experiencing an issue"



9 Q113. Can you provide an overview of how the Company has created, and is 10 leveraging, the end-to-end monitoring of customer Outages through its 11 investments in the EFC - Outage Status initiative? 12 A113. Yes. Prior to the EFC – Outage Status initiative, we did not have one central 13 location to monitor customer outages and the related customer experience during 14 their outage. The systems available allowed us to monitor our progress on outage 15 restoration, but we had no monitor for what customers were experiencing. For 16 example, we did not have a good representation of how many customers were 17 experiencing outages, if they had estimates, or if their estimate was about to expire. 18 Furthermore, the Company had no visibility into the status of outage notifications

Line
<u>No.</u>

1	to customers. During several of the 2021 storms, we found there were performance
2	problems causing the system to stop sending notifications, a situation for which the
3	Company had no visibility until hours later. Therefore, customers did not receive
4	proactive information regarding their power status.
5	
6	In August of 2022, the EFC - Outage Status team created a storm dashboard to
7	allow the internal monitoring of the customer experience during storms. We
8	monitor, in real-time, the number of customers out, the number restored, those
9	without restoration estimates, with expiring estimates. We are able to track a
10	customer's estimate and provide a new estimate if we were not able to meet it. This
11	gives our customers the best information on how to plan around their power outage.
12	The dashboard also allows us to monitor our outbound notifications. When we see
13	a dip in the percentages, we are now able to diagnose if there are system issues.
14	This ensures our customers are getting proactive information on their power status.
15	The dashboard was used successfully during the storm over the Christmas holiday
16	(12/23/22 - 12/25/22) to monitor and manage the customer Outage experience.
17	Figure 21 and Figure 22 provide examples of the data captured and monitored in
18	the EFC – Outage Status dashboards.
19	

#### DTE EFC Storm Operations opt Every 30 Customers with Power Restored by Hour Unique premises power restored Storm Name Total Customers Out of Power Customers Out of Power by Hour Unique premises out of power 233 800 1122 1288 AM ●EFC Out ●InService Out ●Override Out Date Range 600 Customers with a Valid Estimate 1/1/2023 8 100 600 1/3/2023 200 Customers without an Estimate Region 121 Ø All County Code C<sub>1</sub> Cust ith an Expired Est Al 12 City [A] Cust rs with Power Restored Zip Code 5,332 Al ant of ETRs Re Trouble Behind Trouble (TBT) for TPS cented in the lat 24 ms Time Until Est 22

#### Figure 21 **Customer Outage Status Dashboard**

2





1

1	Q114. Why did the Company include a new Outage map as part of its EFC – Outage
2	Status initiative?
3	A114. The current Outage map has a number of shortcomings that limit its effectiveness
4	in providing customers with the most accurate and timely view of outages in their
5	region, neighborhood, and at their premise. It is a customized solution, on an
6	outdated platform, with limited features, that frequently experiences performance
7	issues during large-scale catastrophic storms.
8	
9	To address these issues, the Company is launching a new, industry-standard Outage
10	map (Kubra) with elastic scalability for peak loads, multiple outage views (county,
11	zip code, premise), faster processing times, alignment with service channels for
12	consistent presentment of outage data, enhanced messaging, and links to useful
13	information (Figure 23).
14	

# Figure 23 Kubra Outage Map – Sample Views



Current Outage Map

- Single View
- Limited Messaging
- Less Frequent Updates (up to 20 minutes)
- Lack of Alignment with Service Channels
- Inconsistent Performance



2

4

# 3 Q115. What other projects in the Customer IT Portfolio support the enhancement of

- the Company's customer interactions and communications?
- 5 A115. The Company is investing \$11.7 million in four additional projects in Exhibit A-
  - 12, Schedule B5.7.3 that will modify the Systems of Engagement (Figure 3) to:
- 7

6



1

Line <u>No.</u>	<b>M. J. HATSIOS</b> U-21297
1	• Standardize communication platforms across organizations/transactions.
2	• Increase the flexibility and efficiency with which customer communications
3	are created and maintained.
4	• Allow the Company to capture real-time customer feedback for the ongoing
5	continuous improvement of customer transactions.
6	
7	I will discuss these projects in order of magnitude as they appear in Exhibit A-12,
8	Schedule B5.7.3:
9	
10	1. Line 34 – Customer Service Sales and Service
11	The Company is investing \$7.3 million in test period capital to implement the
12	Customer Service Sales and Service project (Line 34, Exhibit A-12, Schedule
13	B5.7.3). This "Sales" functionality provides the ability to run campaigns and to
14	segment customers who would be most interested and benefit from the Company's
15	products and services. By providing the in-application segmentation capability, it
16	reduces our reliance on and the ongoing cost of using external vendors. The
17	"Service" functionality provides a ticket and order creation and tracking capability
18	that the Company does not have today. The current SAP functionality for tracking
19	of orders is not built into our SAP program today. We use the Business Process
20	Exemption Management (BPEM) to create an event to track the order. However,
21	since the BPEM workflow is not meant to be a ticket / order system, it lacks the full
22	visibility of where the order is in the process. The project will enable the ability
23	for tracking customer requests from start to end and direct the work to the
24	appropriate business units to complete the request. More importantly, it will provide
25	customers and DTE back-office employees full visibility on the status of any

Line <u>No.</u>	M. J. HATSIOS U-21297
1	service request. This application is often described as a tool to provide the Company
2	and customers a 360-degree Customer Service View.
3	
4	2. <u>Line 33 – Customer Service Communications</u>
5	On any given day (assuming no significant outages) the Company sends out on
6	average 165,000 notifications to customers. During large storm events, this number
7	increases significantly and generally exceeds 1,000,000 per day, so on an annual
8	basis, the Company sends out about 60,000,000 customer notifications. Despite
9	the high volume of notifications, the Company sends, the current communication
10	platform for notifications struggles to consistently send customer notifications in a
11	timely manner and cannot easily scale up to the volume of notifications to be sent.
12	There is also no reliable record of the content of these notifications and if the
13	customer received the notification.
14	
15	Under storm conditions when all our customer and communication systems are put
16	to the test and must perform during peak times, the current notification platform
17	cannot be relied upon to deliver the volume of customer notifications. As we make
18	improvements to the quality (e.g., restoration estimate accuracy, timeliness, clarity)
19	of our customer outage status notifications as part of the EFC Outage Status project,
20	we need a communication platform that can deliver this information. The quantity
21	of notifications will also grow as we expect to communicate more frequently with
22	our customers by providing updates at multiple stages of the customer's restoration
23	process when they would want to receive updated information about the status of
24	their restoration (in moments-that-matter).

1 To further improve the effectiveness with which we can manage customer 2 communications, and the experience for customers, the Company is investing \$2.9 3 million in 2022 and 2023 bridge period capital, and \$0.44 million in test period 4 capital, to transition to a solution that will utilize an auto-scaling communications 5 platform (i.e., automatically increases capacity during peak demand periods) 6 integrated with a robust, self-service preference management application. The 7 communications platform will support email, SMS and voice call functionality. 8 The preference center will allow customers to self-serve by selecting the types of 9 communications they would like to be notified about, the channel(s) they would 10 like to be notified in, and what times they would like to be notified.

11

12

#### 3. <u>Line 53 – Qualtrics Expansion</u>

13 The Qualtrics customer survey platform supports another important element of the 14 Closed Loop process and communications feedback loop- the ability to reach out, 15 in real-time, to customers at meaningful touch points in the customer transaction to 16 assess customer sentiment, and where necessary, to take action to correct any 17 customer issues and concerns. Real-time surveys, with mechanisms to escalate 18 and "close the loop" with the customer, will help mitigate repeat calls to the Contact 19 Center, improve customer satisfaction with the transaction, and provide the data 20 necessary to continually and more rapidly identify and implement opportunities for 21 improvement based on collecting the voice of the customer. During the 2020 and 22 2021 historical periods, the Company invested \$0.17 million to implement 23 Qualtrics impacting the five key customer transactions, starting with the MIMO 24 transaction. MIMO learnings were captured and used in the expansion of the

#### MJH-134

#### Line No.

survey and the service ticket resolution process to the other four key customer transactions – Outage, Billing, Payments, and Collection.

4 To expand on these efforts, the Company is investing an additional \$0.47 million 5 in 2022 bridge period capital to expand and improve the Qualtrics platform to 6 further augment our ability to effectively manage the customer transactions and 7 elevate the customer experience, unlocking the ability of Qualtrics to do more than 8 just capture customer feedback and create tickets for manual resolution. Qualtrics 9 will be integrated within existing workflows in a manner that will allow it to obtain 10 solicited and unsolicited feedback across any customer interaction and touchpoint 11 (e.g., voice, text, email, or chat), to create a single system of record for those 12 interactions, and to use intelligent analytics to automatically identify issues 13 requiring resolution (without relying on the customer to provide feedback via the 14 ticketing process), and to take real-time action based on that intelligence.

15

16

Line

No.

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3

### 4. Line 21 – SAP Cloud Platform - Foundational Additions

17 The Company will invest \$0.4 million in 2022 bridge period capital to enable core 18 platform capabilities that can be leveraged by current and future projects. The 19 usage of the SAP Cloud Platform continues to grow within the Company. The 20 opportunity to expand the available features to support multiple use cases has 21 become necessary. This project enables multiple features on the platform such as:

- 22
- 23 24

• Customer self-service capability to upload documents (i.e., supporting documentation for filing a claim). Documents will be automatically

Line <u>No.</u>	M. J. HATSIOS U-21297
1	scanned for viruses and then loaded into the Company's customer document
2	repository.
3	• Provide CRs the ability to update customers on the status of their requests.
4	
5	The recommended solution enhances the investment in the Companies' SAP
6	Customer Cloud platform as well as leverages the existing Company application
7	for document storage. To support uploading of customer documents, a certified
8	bolt-on cloud service was chosen to minimize custom application development
9	which is costly and may not be fully compatible with our SAP systems.
10	
11	Part 7. Projects that Reform Collection Experiences
12	Q116. How does the Company intend to reform the Collection customer experience?
12 13	<b>Q116.</b> How does the Company intend to reform the Collection customer experience? A116. The Company's strategy to reform the Collection experience is simple – prudently
12 13 14	Q116. How does the Company intend to reform the Collection customer experience? A116. The Company's strategy to reform the Collection experience is simple – prudently invest capital in projects that provide solutions for customers struggling to pay their
12 13 14 15	<ul> <li>Q116. How does the Company intend to reform the Collection customer experience?</li> <li>A116. The Company's strategy to reform the Collection experience is simple – prudently invest capital in projects that provide solutions for customers struggling to pay their bills, more easily access energy assistance, allow them to and successfully pay</li> </ul>
12 13 14 15 16	<ul> <li>Q116. How does the Company intend to reform the Collection customer experience?</li> <li>A116. The Company's strategy to reform the Collection experience is simple – prudently invest capital in projects that provide solutions for customers struggling to pay their bills, more easily access energy assistance, allow them to and successfully pay down their past due balances, and help them avoid being disconnected for</li> </ul>
12 13 14 15 16 17	<ul> <li>Q116. How does the Company intend to reform the Collection customer experience?</li> <li>A116. The Company's strategy to reform the Collection experience is simple – prudently invest capital in projects that provide solutions for customers struggling to pay their bills, more easily access energy assistance, allow them to and successfully pay down their past due balances, and help them avoid being disconnected for nonpayment.</li> </ul>
12 13 14 15 16 17 18	Q116. How does the Company intend to reform the Collection customer experience? A116. The Company's strategy to reform the Collection experience is simple – prudently invest capital in projects that provide solutions for customers struggling to pay their bills, more easily access energy assistance, allow them to and successfully pay down their past due balances, and help them avoid being disconnected for nonpayment.
12 13 14 15 16 17 18 19	Q116. How does the Company intend to reform the Collection customer experience?A116. The Company's strategy to reform the Collection experience is simple – prudently invest capital in projects that provide solutions for customers struggling to pay their bills, more easily access energy assistance, allow them to and successfully pay down their past due balances, and help them avoid being disconnected for nonpayment.To that end, the Company is investing \$5.7 million in two capital projects, both of
12 13 14 15 16 17 18 19 20	Q116. How does the Company intend to reform the Collection customer experience? A116. The Company's strategy to reform the Collection experience is simple – prudently invest capital in projects that provide solutions for customers struggling to pay their bills, more easily access energy assistance, allow them to and successfully pay down their past due balances, and help them avoid being disconnected for nonpayment. To that end, the Company is investing \$5.7 million in two capital projects, both of which are included in Exhibit A-12, Schedule B5.7.3:
12 13 14 15 16 17 18 19 20 21	Q116. How does the Company intend to reform the Collection customer experience? A116. The Company's strategy to reform the Collection experience is simple – prudently invest capital in projects that provide solutions for customers struggling to pay their bills, more easily access energy assistance, allow them to and successfully pay down their past due balances, and help them avoid being disconnected for nonpayment. To that end, the Company is investing \$5.7 million in two capital projects, both of which are included in Exhibit A-12, Schedule B5.7.3:
12 13 14 15 16 17 18 19 20 21 22	Q116. How does the Company intend to reform the Collection customer experience? A116. The Company's strategy to reform the Collection experience is simple – prudently invest capital in projects that provide solutions for customers struggling to pay their bills, more easily access energy assistance, allow them to and successfully pay down their past due balances, and help them avoid being disconnected for nonpayment. To that end, the Company is investing \$5.7 million in two capital projects, both of which are included in Exhibit A-12, Schedule B5.7.3: 1. Line 8 – Payment Stability Plan (PSP) Program (\$1.4 million)
12 13 14 15 16 17 18 19 20 21 22 23	Q116. How does the Company intend to reform the Collection customer experience? A116. The Company's strategy to reform the Collection experience is simple – prudently invest capital in projects that provide solutions for customers struggling to pay their bills, more easily access energy assistance, allow them to and successfully pay down their past due balances, and help them avoid being disconnected for nonpayment. To that end, the Company is investing \$5.7 million in two capital projects, both of which are included in Exhibit A-12, Schedule B5.7.3: <ol> <li>Line 8 – Payment Stability Plan (PSP) Program (\$1.4 million)</li> <li>Line 14 – Advanced Analytics Use Cases (\$4.3 million)</li> </ol>

# Q117. Can you describe the scope and intent of the Payment Stability Plan (PSP) Pilot Project?

A117. While Low Income Assistance (LIA) and Residential Income Assistance (RIA)
credits reduce the bills of vulnerable customers and address energy sustainability,
there remains opportunity to address ongoing burden of energy usage costs for lowand moderate-income customers. These DTE customers require a plan that offers
payment stability, while also encouraging and rewarding reduced energy
consumption. To that end, the Company has identified five criteria for inclusion in
a best-in-class income program (Figure 24).

10

#### 11 Figure 24 Low Income Payment Program Best Practices

#### Percentage of Income

 Adjusting the bill rate to an affordable rate recognizes the essential role played by home energy burdens in defining home energy affordability

#### **Retire Existing Arrears**

· Raising the overall monthly asked-to-pay amount to an affordable level to retire arrears within a reasonable period

#### **Protect Bill Volatility**

· Facilitating or requiring entry into levelized budget billing plans will protect the customer from the unexpected

#### Promote Energy Efficiency

· Through investments in usage reduction measures and preservation of conservation incentives in the rate structure

#### **Preserve Funds for Crisis**

· Poverty-level households may experience crisis events that are caused by the fragility of income

12

13	These best practices have informed the design of the PSP program, which was
14	approved as a pilot by the Commission in its April 21, 2021 order in MPSC Case
15	No. U-20929, in which Affiant Maria Christian describes the details of the PSP
16	program design and the expected outcomes and benefits to customers. The \$1.4
17	million in 2021 historical period (\$1.0 million) and in 2022 bridge period (\$0. 4

Line No.	M. J. HATSIOS U-21297
1	million) capital (Line 8 of Exhibit A-12, Schedule B5.7.3) was used to fund the
2	system hardware and software changes required to implement the pilot.
3	
4	Q118. How is the Company leveraging Advanced Analytics to improve the Collection
5	Process and customer experience?
6	A118. Like all companies, DTE is investing in resources and technologies that will
7	provide greater insight into customer segments, behaviors, and the customer
8	experience. To that end, the Company is investing \$4.3 million in bridge (\$1.8
9	million) and test (\$2.5 million) period capital, in the Advance Analytics (AA) Use
10	Cases project (Exhibit A-12, Schedule B5.7.3, Line 14).
11	
12	Reflected in the requested bridge and test period capital are three analytics use cases
13	related to optimizing those process that support the manner in which the Company
14	assists those customers who struggle to pay their bills, with the goal of making
15	easier to navigate the energy assistance process and to reduce friction points and
16	customer dissatisfiers in the Company's Collection processes. The remainder of
17	my response to questions summarizes the scope of these use cases by the calendar
18	year in which they are implemented:
19	
20	1. <u>2022 Use Cases - \$1.4 million</u>
21	The Company has developed a machine learning model to generate insights on the
22	propensity of inactive customers (i.e., customers that are already
23	disconnected/moved out and are no longer receiving service) to repay accrued
24	balances. We know that sometimes customers pay off their balance, in part or in
25	full, months after they are accrued, occasionally even a long time after their service

2

3

4

5

has been interrupted. In other cases, customers never pay the accrued balance. We want to improve our understanding of what drives customer behavior once notable balances are accrued, and to improve our ability to intervene and support our customers, especially the ones that are actively trying to pay off their balance.

6 The Company has also developed a machine learning model to improve the 7 understanding of those areas of the transaction that customers find most difficult 8 and for which they express the most dissatisfaction. This model will allow us to 9 gain a more quantitative understanding of what our customers consider most 10 important in shaping their level of satisfaction and perception of the Company, 11 allowing us to adapt our strategy and prioritize our customers' needs and 12 expectations. This investment is essential to be able to create targeted, cost-efficient 13 initiatives to maintain and increase overall customer satisfaction with the Company 14 and transaction satisfaction.

15

16

#### 2. <u>2023 Use Cases – \$0.4 million</u>

In 2023, we will use machine learning to integrate the findings from the 2022 use cases and improve our understanding of inactive customers' propensity to pay their balance. Today, collection agencies are assigned customers at random, regardless of the agency's performance. The integration of the predicted recovery rates from the 2022 modeling into the SAP CR&B system, will help us optimize the allocation of customers to collection agencies, reducing the amount of collection agency fees that the Company pays by \$40,000 a year.

- 24
- 25 3. <u>202</u>

3. <u>2024 Use Cases – \$2.5 million</u>

1 Energy assistance is available to our low-income customers whose balances are 2 past due or who are otherwise qualified for assistance. However, customers must 3 reach out to DTE or third-party energy assistance agencies to receive this energy 4 assistance. As the process is set up, the customer needs to be proactive in seeking 5 energy assistance and therefore the funding available could be underutilized. 6 7 A machine learning model will be developed in 2024 that can help with predicting 8 the likelihood of a customers' energy assistance eligibility, with these probability 9 scores used by the Company to proactively promote energy assistance to our most 10 vulnerable low-income customers. Given the seven different types of low-income 11 energy assistance customers can receive (e.g., LSP, HHC, SER, MEAP, Non-12 MEAP, RIA and LIA) and the various ways in which a customer can enroll for 13 these assistance programs (such as through a state application, tax form, or by 14 contacting DTE), a machine learning model will help remove this burden from 15 customers by sifting through all these factors and matching customers to the right 16 program(s) that best fit their needs and circumstances. 17 18 Part 8. EWR & Clean Energy Projects 19 Q119. What is motivating the Company's investments in projects to boost EWR and 20 provide clean energy for all those in Michigan? 21 A119. DTE Electric customers are becoming more aware of, and interested in, 22 opportunities to reduce their energy usage, lower their monthly bills, and reduce 23 their carbon footprint. As such, the Company is continually investing in the 24 expansion and creation of products and services that allow customers to reduce their

25 usage, save money, and contribute to a cleaner environment.

Line	<b>M. J. HATSIOS</b> U-21297
<u>No.</u>	
1	
2	Q120. Which projects in Exhibit A-12, Schedule B5.7.3 support the ability of
3	customers to lower their usage, save money, and reduce their carbon
4	footprint?
5	A120. There are seven projects in Exhibit A-12, Schedule B5.7.3, total \$42.5 million in
6	historical, bridge, and test period capital that help customers conserve energy, lower
7	their monthly bills, and reduce their carbon footprint:
8	
9	1. Line 1 – ACCP/TOD (\$18.1 million)
10	2. Line 3 – MIGP Fixed Price Product/Rider 17 (\$3.4 million)
11	3. Line 4 – MIGP Low Income Solar Pilot (\$2.8 million)
12	4. Line 5 – MIGP Website Update (\$1.5 million)
13	5. Line 6 – MIGP Section 61 Settlement (\$4.3 million)
14	6. Line 10 – Rider 17: MIGreenPower, Residential and Small
15	Commercial & Industrial (\$4.0 million)
16	7. Line 11 – MIGP Customer-Requested Renewable Energy Projects
17	(\$8.4 million)
18	
19	It should be noted that these projects (or programs) are part of the
20	Regulatory/Compliance category of Customer IT Portfolio investments, but have
21	been separated here for the purposes of my testimony as they align with this
22	important Company priority.
23	
24	Q121. Can you elaborate on the status of the Company's ACPP/TOD project?

Line <u>No.</u>		M. J. HATSIOS U-21297
1	A121.	ACPP is a pilot program that was previously approved by the Commission in MPSC
2		Case No. U-20602 and which included the pilot implementation of two TOD rates.
3		The ACPP concluded in 2022.
4		
5	Q122.	How is the \$18.1 million in historical, bridge, and test period capital on Line 1
6		of Exhibit A-12, Schedule B5.7.3 being allocated to support the ACPP pilot
7		and ongoing implementation of TOD rates?
8	A122.	As described in MPSC Case No. U-20602, IT expenditures related to the
9		ACPP/TOD project support the technical implementation of the rates in the core
10		SAP billing and interfacing customer systems and required modifications to the
11		meter data management system and customer facing digital channels. IT is
12		additionally accountable for the technical creation of new microsites supporting
13		customer communication and pilot Web enrollment. The bulk of the capital
14		investment is allocated to core SAP system modifications (~60%), digital channel
15		modifications (~15%), and modifications to the meter data management system
16		(~12%).
17		
18		The Company invested \$15.2 million in 2019 and 2020 historical capital, and
19		invested an additional \$2.1 million in 2021 historical capital, in support of the
20		implementation of the ACPP pilot rates. In its November 18, 2022 Order in Case
21		No. U-20836, the Commission approved the Company's Alternative TOD Plan. We
22		are investing \$16.0 million in 2022 and 2023 bridge period (\$14.8 million) and test
23		period (\$1.2 million) capital (with no contingency costs) to complete the TOD
24		Alternative Full Implementation project.
25		

1	Q123. Can you elaborate on the \$26.7 million investment in the MIGreenPower
2	(MIGP) and Renewable Energy programs?
3	A123. Yes. The \$26.7 million in capital in the historical, bridge and test periods is being
4	allocated to six MIGP renewable energy projects, as reflected in Exhibit A-12
5	Schedule B5.7.3, Lines 3-6 and 10-11. These investments satisfied the Company's
6	commitments to the MPSC and our customers under the approved renewable
7	energy plan (U-20851 and U-20713).
8	
9	Below I provide a summary of each of the MIGP projects for which the Company
10	is requesting recovery in the instant case, in order of their line number in Exhibi
11	A-12, Schedule B5.7.3. Each of these MIGP tariffs have been approved by the
12	MPSC for implementation, with the associated capital dollars reflecting the
13	investment necessary to build the required fixed or volumetric charges in the CR&E
14	system, to enroll customers, to update the Company Website, and to create
15	supporting internal dashboarding and reporting that supports the program.
16	
17	1. Line 3 – MIGP Fixed Price Product (Rider 17)
18	The Company invested \$3.7 million in historical 2021 period (\$0.8 million) and
19	2022 bridge period (\$2.9 million) capital in the MIGP Fixed-Price Product (Rider
20	17) project. This project provides DTE Electric customers with the ability to enrol
21	in a fixed price version of the existing Rider 17 offering. Customers will be able to
22	choose a fixed-price option of, for example, \$5 or \$10 per month, and will be billed
23	accordingly. While the functionality in the billing and associated systems have
24	been technically completed and in production, the Company cannot offer a fixed
25	price product based on the current forecasts of projected negative net premium
1 values for the 2023-2024 program year. When a very small or negative net 2 premium is calculated for a program year, the fixed price product mathematically 3 cannot be offered (since the net premium of zero dollars) in order to stay in 4 compliance with the requirement that enrollees are limited to energy usage in the 5 last 12 months. Therefore, the Company has postponed offering this product after 6 it went live in August 2022 and will re-evaluate in mid-2024. 7 8 2. Line 4 – MIGP Low-Income Solar Pilots 9 The Company is investing \$2.4 million in bridge period, and \$0.4 million in test 10 period capital, in the MIGP Low-Income Solar Pilots to provide the IT functionality 11 in the CR&B system to comprehend the Pilot's program parameters and objectives 12 and enroll qualified low-income customers in the program. Additional 13 functionality must also be developed in the system to collect donations that will 14 offset the premium required for providing solar energy-sourced power to enrolled 15 customers. This project will expand MIGP offerings to low-income customers who 16 might not otherwise be able to participate in the program, and by enabling anyone, 17 whether a DTE customer or not, the option to contribute into a low-income 18 renewables fund. The funds from these voluntary contributions would be used in 19 tandem with third-party donations to fully-subsidize MIGP subscriptions for low-20 income customers. The system capability to offer this program is addressed in the 21 Company's Section 61 filing in MPSC Case No. U-20713, where further details of 22 this and all MIGP programs can be found. 23 24 3. Line 5 – MIGP Website Update

1 The Company invested \$1.4 million in historical 2021 period (\$0.6 million) and 2 2022 bridge period (\$0.8 million) capital in the MIGP Website Update project. A 3 redesign and update to the MIGP Website and migration to the Cloud platform in 4 line with the Company's cloud strategy and roadmap for all non-core processes and 5 applications as described in the DTE IT five-year plan supported by Witness Sharma's testimony in the instant case. This upgrade improved the customer 6 7 experience and ease of use. A revamped process for new customer enrollments and 8 for providing existing customers the ability to change their enrollment level reduced 9 complexity and improved the customer experience. This project provides greater 10 flexibility with guest enrollment and the customer identification process.

11

12

Line

No.

#### 4. <u>Line 6 – MIGP Section 61 Settlement</u>

The Company invested \$4.3 million in historical 2021 period (\$0.5 million) and 13 14 2022 bridge period (\$3.8 million) capital in support of the MIGP Section 61 15 Settlement (Settlement) in MPSC Case No. U-20713. To fulfill obligations of the 16 Settlement, the existing Rider 17 and Rider 19 no longer have separate tariffs, 17 eliminating the need for the wind-only and wind-solar Combo programs. A new 18 volumetric-based program was designed in a very similar manner to the Combo 19 program. The project scope includes several key objectives: (1) updating training 20 materials and internal reports, (2) Website updates to reflect the new program, (3) 21 retirement of existing Wind and Combo programs, and (4) conversion of all current 22 customers to the new volumetric-based program. Note that this project is 23 independent of, and mutually exclusive to, the MIGP Fixed Price Product described 24 on Line 3 discussed above.

25

Line <u>No.</u>	<b>M. J. HATSIOS</b> U-21297
1	5. Line 10 – Rider 17 MIGP, Residential, Small Commercial, and Industrial
2	The Company is investing \$4.0 million in 2023 bridge period (\$1.3 million) and
3	projected 2024 test period (\$2.7 million) capital in the Rider 17 MIGP Residential,
4	Small Commercial, and Industrial project.
5	
6	This project replaces the Rider 19 MIGP Large Commercial & Industrial project as
7	Rider 19 ended on August 19, 2022 and is now merged with Rider 17. The project
8	scope includes CR&B system changes required to create a fixed price offering for
9	large customers and the ability to enroll residential and streetlighting accounts, bill
10	customers, and other enhancements to manage and administrate the program.
11	
12	6. <u>Line 11 – MIGP Customer-Requested Renewable Energy Projects</u>
13	The Company is investing \$5.1 million in bridge period, and \$3.3 million in test
14	period, capital in Customer-Requested Renewable Energy Projects. These projects
15	are unique contracts between a company and DTE to build dedicated renewable
16	assets to offset their electricity use. The Company has entered into agreements with
17	two uniquely contracted customers, Ford and Stellantis Partners, to build two
18	dedicated solar parks with 650 MW and 400 MW of capacity, respectively. Similar
19	in scope to many of our MIGP renewable projects, this project will include end-to-
20	end enhancements to the CR&B system that will include billing, reporting,
21	accounting, and enrollment functionality for individual customer-requested
22	projects, and any additional updates to fulfill the Company's commitment under
23	these contracts. These unique contracts require the creation and integration of a
24	new product named "customer-requested solar park" into the SAP CR&B system

Line <u>No.</u>	M. J. HATSIOS U-21297
1	and will require enhancements and integration with SAP Business Warehouse
2	(BW) and SAP Commerce Cloud.
3	
4	Q124. Is the Company investing in any other projects related to supporting the
5	management of the MIGP Programs or to integrate its renewable programs
6	with other products and services?
7	A124. Yes. The Company is also investing \$2.2 million in two MIGP projects that will
8	enhance the management of the MIGP programs and that will integrate the MIGP
9	programs with other products and services, both of which are reflected in Exhibit
10	A-12, Schedule B5.7.3 as follows.
11	
12	1. Line 46 – MIGP Data and Reporting
13	The Company is investing \$1.9 million in 2023 bridge (\$0.8 million) and projected
14	test (\$1.1 million) period capital in this solution which will allow the Company to
15	efficiently track and manage MIGP and private solar enrollments, usage data,
16	revenue, and more. The current dashboard and reports rely on a manual process of
17	exporting reports from the source system, analyzing the results, and then importing
18	files to view in a dashboard. A more efficient solution would allow a new dashboard
19	to be updated directly from the source system without manual intervention, and in
20	real-time. In addition, the existing process is becoming un-sustainable as the
21	number of MIGP enrollments continues to grow. The upward trend in the volume
22	of data points being processed is contributing to further slowdowns in processing
23	time.
24	
25	2. Line 47 – MIGP Integrate DTE Insight

1	The Company invested \$0.3 million in 2021 historical (\$0.15 million) and 2022
2	bridge (\$0.18 million) capital in this project. The intent of this project is to improve
3	the participation of DTE Insight APP customers that may also willing to participate
4	in MIGP programs by improving their awareness of this program and ther
5	encouraging their enrollment. With the integration of MIGP program enrollmen
6	and the DTE Insight APP, we expect to retain a high percentage of Insight APP
7	users with engagement features to maintain their enrollment in the MIGP programs
8	
9	Part 9. Regulatory and Compliance Projects
10	Q125. Which Regulatory and Compliance projects will you discuss in this section of
11	your testimony?
12	A125. As previously highlighted, Regulatory/Compliance investments are non-
13	discretionary investments required to satisfy MPSC standards and orders, and other
14	industry regulations and compliance items the Company must adhere to in order to
15	provide service to its customers. This includes the MIGP projects I discussed ir
16	Part 8 of my testimony, along with five other projects totaling \$9.0 million in capita
17	from Exhibit A-12, Schedule B5.7.3:
18	
19	1. Line 2 – Corporate Energy Forecasting (\$0.3 million)
20	2. Line 7 – PCI Compliance (\$0.4 million)
21	3. Line 9 – Regulatory Compliance (\$6.5 million)
22	4. Line 12 – Securitization (\$0.6 million)
23	5. Line 13 – Treasury Credential on File (\$1.2 million)
24	

1	Q126.	What is the scope of the Corporate Energy Forecasting Project on Line 2 of
2		Exhibit A-12, Schedule B5.7.3?
3	A126.	The Company invested \$0.26 million in 2022 bridge period capital in the
4		development of an integrated Corporate Energy Forecasting solution designed to
5		improve the Company's forecasting of energy usage by customer class, delivering
6		a full 8,760 hourly profile at the circuit level for the length of the forecast horizon.
7		The project required the purchase of Metrix IDR software. Metrix IDR is an
8		ITRON forecasting software fully compatible with current ITRON forecasting
9		software utilized by the Corporate Energy Forecasting team (Metrix ND and Metrix
10		LT) in producing the current Service Area forecast.
11		
12		The Company's innovations in energy forecasting methods and tools to support
13		both distribution and resource planning are discussed in more detail in the
14		Distribution Grid Plan filed September 30, 2021, in MPSC Case No. U-20147.
15		
16	Q127.	What is the PCI Compliance project on Line 7?
17	A127.	PCI Compliance refers to DTE's adherence to the PCI Data Security Standards
18		(PCI (DSS) established by the credit card industry and audited by a certified PCI
19		Security Assessor.
20		
21	Q128.	Why does DTE need to maintain PCI compliance?
22	A128.	35-40% of payments received from customers are made using a credit or debit card.
23		To accept, store, process, and transmit payments and cardholder data, DTE must
24		adhere to PCI DSS. Failure to adhere to PCI DSS could result in the loss of payment
25		certification with our banking partners and would prevent us from being able to

1 accept credit or debit card payments. DTE invested \$3.0 million in 2019 to achieve 2 PCI DSS compliance, and an additional \$0.4 million in historical (\$0.1 million), 3 bridge (\$0.1 million), and test (\$0.2 million) period capital in the instant case, to 4 maintain that compliance to the most recent standards. As mentioned in my 5 testimony in this instant case for the Secured Cloud Payment Provider project (A-6 12 Schedule B5.7.3 Line 54), the amount of the Company's PCI compliance 7 requirements and associated processes will be reduced when this project is 8 implemented as the new vendor will be entirely responsible for ensuring PCI 9 compliance with regard to accepting credit card payments.

10

# Q129. Is there another project that was implemented in 2022 that is associated with maintaining PCI compliance?

13 A129. To maintain continued compliance and the ability to accept credit card payments, 14 DTE also invested \$1.3 million in 2022 bridge capital in the Treasury Credential 15 on File (A-12 Schedule B5.7.3 Line 13) project to upgrade its payment systems to ensure compliance with the new credit card standards to capture PCI-mandated data 16 17 fields described below during credit card payment transactions. Visa and 18 Mastercard mandated and introduced a requirement to authenticate customer and 19 merchant-initiated transactions, which states that as a merchant, DTE "must obtain 20 cardholder consent before storing card details for future use, and that these must be 21 flagged at the time of the first authorization, by submitting the credentials on file 22 field in your requests. You must also flag any subsequent payments that are 23 utilizing previously stored credentials, by including the credentials on file field in 24 these requests".

1

### Q130. What type of projects are included in the Regulatory Compliance line item?

A130. The Regulatory Compliance project (on Line 9 of Exhibit A-12, Schedule B5.7.3)
is intended to fund system changes necessary to comply with the outcome of any
MPSC rate orders, to provide funding for emerging regulatory compliance items,
and to fund the implementation of new rates and programs as approved by the
MPSC. To that end, the Company is investing \$6.5 million in historical (\$0.03
million), bridge (\$3.7 million), and test (\$2.8 million) period capital, to fund
ongoing and emerging rate changes required to be implemented in the system.

10 The 2021 Regulatory Compliance project business case was originally estimated at 11 \$2.2 million in capital, which included the capital required to implement the PSP 12 pilot (Line 8) and the Securitization (Line 12) projects. Both projects were later 13 separated from the Regulatory Compliance project, along with the associated 14 capital funding. As such, the 2021 spend for the Regulatory Compliance project 15 was reduced from the original \$2.2 million to \$25,000.

16

9

In 2022, funding from the Regulatory Compliance project supported the roll-out of the D13 rate as DTE Electric proposed a D13 XL-HLF rate to provide the Company the opportunity to optimize its load base and make incremental contributions to DTE Electric's fixed costs. The D13 rate aimed to provide customers with competitively priced electricity consistent with cost-of-service-based rates to address the changing circumstances of its automotive and other advanced manufacturing customers.

1

2

3

4

5

In 2023, this project as in prior years provides a yearly investment that allows DTE to implement IT system changes inclusive of logic and screen changes to the CR&B system, the Agency Website/Online Resource for Energy Assistance Agencies (AGW/ORA) applications and StreamServe for bill formatting changes to support emergent Regulatory work.

6

7

8

9

10

11

In the 2024 test period, as described by Witness Willis in his testimony related to the Company's proposal for transitioning D1.6 customers to the new D1.11 TOD rate and closing the D1.6 rate, investments from the Regulatory Compliance project will fund the CR&B system changes required to complete the three key elements of the transition.

12

13 Currently, the LIA credit of \$40/month is available only to customers taking service 14 on D1.6 - a customer who is otherwise eligible but chooses to take service on a 15 different base rate may not avail themselves of the credit. The transition to Time-16 of-Day rates provides an opportunity not only to realign rate design for D1.6 17 customers, but also to expand their ability to choose their base rate schedule while 18 retaining the LIA credit. The Company anticipates the implementation of this 19 transition will occur during the projected test year. Thus, the Company's Exhibit 20 A-16, Schedules F3 and F8 both reflect the continuation of D1.6 into the projected 21 test year given the requirement to continue utilizing the rate for a period of time. 22 In addition to the scope previously described, this project also ensures there is 23 sufficient funding for planned and emergent revisions to electric rates, amendments 24 to rate schedules and rules governing the distribution and supply of electric energy, 25 and any other modifications of DTE Electric rates in accordance with MPSC orders.

**M. J. HATSIOS** 

U-21297

1

### 2 Q131. Can you describe the scope of the Securitization Project on Line 12?

3 A131. DTE filed MPSC Case No. U-21015 requesting MPSC approval to issue 4 securitization bonds and implement a surcharge related to the cost of the 5 Company's retirement of the River Rouge power plant and a surge in tree trimming 6 costs. The Commission granted approval for the securitization of up to \$235.8 7 million in qualified costs on June 23, 2021. The Company invested \$0.6 million in 8 2021 historical period capital to make the necessary rate changes in the billing 9 system, which includes two new securitization surcharges for residential, industrial, 10 and commercial customers.

11

#### 12 Part 10. Voluntary PrePay Pilot

#### 13 Q132. What is a prepayment?

14 A132. A prepayment is a payment that is made before one receives goods or services.

15

# Q133. How will a prepaid electricity program work in your proposed Voluntary Prepay Pilot?

A133. The Company's proposed Voluntary Prepay Pilot (PrePay Pilot) will work in a
 manner that is consistent with other prepaid electric billing programs. I will fully
 describe the design and execution of the Company's proposed pilot program in a
 subsequent portion of my testimony. Here I will describe in general the concept
 and core design principles of prepaid electric billing programs.

23

24 Customers with electric AMI meters purchase electricity in advance by adding 25 credits to their account. As their account credits reach predetermined levels, the

<u>No.</u>	
1	customer is notified of the estimated number of days of usage remaining in their
2	account, after which time they will run out of credits and be subject to shutoff if
3	additional deposits are not made. These notifications are provided to customers in
4	their preferred communication channel (e.g., SMS/text, email). In the event the
5	customer fails to replenish their account and the balance drops below zero, the
6	customer is remotely disconnected. While there are no deposits or reconnection
7	fees, in order to restore service, the customer needs to add enough money to their
8	account to cover the cost of any unpaid usage plus a minimum amount to reestablish
9	a positive credit balance. Prepay customers can check their balance, view their
10	energy consumption, and replenish their accounts anytime they want through
11	various electronic service channels.
12	
13	DTE Prepaid Billing Proposals
14	Q134. Has the Company requested recovery of prepaid billing capital expenditures
15	in a prior DTE Electric rate case?
16	A134. Yes. The Company requested recovery of \$12.6 million (\$8.0 million in bridge and
17	\$4.6 million in test period) of capital expenditures for its proposed voluntary DTE
18	PrePay billing program in DTE Electric's Rate Case No. U-20836.
19	
20	Q135. What was the outcome of the Company's request for recovery of the DTE
21	PrePay capital expenditures in Case No. U-20836?
22	A135. In its November 18, 2022 Case No. U-20836 Order, the Commission disallowed
22	the DTE Durber was seen it is a literate of the

Line

24

but rather on the fact that it had not yet rendered a decision regarding approval of

## MJH-154

Commission did not base their disallowance on the merits of the PrePay program,

Line <u>No.</u>		M. J. HATSIOS U-21297
1		the program and the associated Billing Rule waivers, both of which were requested
2		in DTE Electric's PrePay Case No. U-21087.
3		
4	Q136.	Has the Commission issued its final order in the U-21087 PrePay case?
5	A136.	Yes. In its December 21, 2022 Case No. U-21087 Order, the Commission denied
6		the Company's request to implement a DTE PrePay program, as it was described
7		by the Company in Case No. U-21087.
8		
9		However, while the Commission denied the Company's request to implement its
10		voluntary DTE PrePay program, and its request for a suspension of a subset of the
11		Billing Rule waivers for customers who would voluntarily enroll in DTE PrePay,
12		the Commission did, in its December 21, 2022 Case No. U-21087 Order, state that:
13		
14		"a prepay program could provide beneficial innovations for managing energy
15		costs and consumption for certain customers if properly designed and vetted.
16		Therefore, the Commission finds that DTE Electric may refile its request for a
17		Prepay Program and associated waivers under the established objective criteria
18		for approval of a pilot program and required comprehensive plan established by
19		the October 29 order".
20		
21	Q137.	Is the Company requesting recovery of capital for its proposed voluntary
22		PrePay Pilot in the instant case?
23	A137.	Yes. The Company is requesting recovery of the \$6.7 million in Pre-Pay historical
24		capital shown in Exhibit A-12, Schedule B5.7.3, Line No. 51. The Company will

Line M. J. HATSIO U-2129
<u>No.</u>
1 withdraw its request for recovery of the \$2.6 million in test period Pre-Pay Phas
2 II capital shown in Exhibit A-12, Schedule B5.7.3, Line No. 52.
3
4 Q138. What is the Company's rationale for continuing to request recovery of the \$6.
5 million in historical Pre-Pay capital?
6 A138. The Company has already invested the \$6.7 million in capital to build what
7 defined as Phase 1 of its proposed PrePay program, as described in Case No. U
8 21087. This solution was deployed into the production CR&B system in December
9 of 2021. The deployed solution includes all of the core functionality required t
10 support a prepaid billing program, and can be used, with some configuration
11 changes, to implement the proposed PrePay Pilot.
12
13 As such, the Company considers it reasonable and prudent to seek approval for th
14 implementation of a voluntary PrePay Pilot, a waiver of a subset of the MPSO
15 billing rules, and recovery of the \$6.7 million in historical Pre-Pay project capita
16 to support the PrePay Pilot as further described in this testimony. While som
17 amount of investment may be required to modify the already deployed solution t
18 support the final design of the PrePay Pilot, the Company is not seeking recover
19 of these potential incremental costs in the instant case as they are not certain.
20
21 Q139. Has the Company provided the objective criteria for utility pilots a
22 established in the 10/29/2020 Commission order in U-20645 as part of it
23 request for approval of its PrePay Pilot?

Line <u>No.</u>		M. J. HATSIOS U-21297
1	A139.	Yes. The Company is providing, in Exhibit A-24, Schedule N11, all of the
2		applicable objective criteria established in Case No. U-20645 for its proposed
3		PrePay Pilot.
4		
5	Q140.	How does the voluntary PrePay Pilot, differ from the permanent program that
6		was proposed in Case No. U-21087?
7	A140.	The basic eligibility requirements, structure, and management of accounts for the
8		PrePay Pilot will not be any different than what was described as Phase 1 of the
9		proposed voluntary DTE PrePay program in Case No. U-21087. However, the
10		Company considered the feedback it received from the MPSC Staff, the Intervenors
11		in Case No. U-21087, and from the Commission's December 21, 2022 Case No.
12		U-21087 Order, and is designing its proposed PrePay Pilot to address, to the extent
13		possible, their identified areas of concern and implement their recommendations.
14		
15	Q141.	Which aspects of its originally proposed DTE PrePay program is the Company
16		proposing to change for its proposed PrePay Pilot?
17	A141.	The proposed voluntary PrePay Pilot being requested in this case will differ from
18		the proposed voluntary PrePay program the Company requested in Case No. U-
19		21087 in the following areas:
20		
21		1. <u>Number of Enrollments</u>
22		The Company in its proposed PrePay program in Case No. U-21087, indicated that
23		it would enroll up to 3,000 customers in the first year of implementation of that
24		program, and that it was targeting to enroll 40,000 customers in the first five years.
25		Concerns were expressed that the Company was asking for a permanent program,

3

with no additional discussion or approval required to expand the program to 40,000
 customers.

To alleviate these concerns, the Company is requesting approval to enroll up to 3,000 customers in its proposed PrePay Pilot over a 2-year period. Any expansion of the program and the number of customers enrolled, during or after completion of the pilot, would require approval of the Commission.

8

9

### 2. <u>Pilot Eligibility</u>

10 Identical to what was proposed for Phase 1 of the PrePay program in U-21087, pilot 11 program participation will be available on a voluntary basis to all residential DTE 12 Electric customers with a single AMI meter, but will exclude customers with 13 medical issues, active military members, customers with multiple premises, 14 customers already enrolled in other payment (e.g. LSP, PSP, SPP, BWB) and non-15 payment (e.g., MIGP, HPP) programs, and dual commodity (DTE Electric + DTE 16 Gas) customers. Additionally, the Company will not enroll any senior customers 17 on the PrePay Pilot – in Case No. U-21087 the Company had proposed allowing 18 enrollment for seniors and excluding only those that were enrolled in the Winter 19 Protection Plan (WPP).

- 20
- 21 3. <u>Arrears Threshold</u>

The Company will lower the arrears threshold permitted at enrollment, from the proposed \$750 in the U-21087 PrePay program filing, to \$250 for the proposed PrePay Pilot in the instant case. This will allow customers, who choose to enroll with arrears, to pay off their arrears balance in less than 12 months through the

1 application of 20% of each prepayment to their arrears balance. The \$250 maximum 2 arrears threshold was established based on the assumption that PrePay Pilot 3 participants who enroll with arrears use on average the same ~625kWh of 4 electricity per month as the average DTE Electric residential customer (2022), 5 which results in a total month bill of  $\sim$ \$120. 6 7 For example, if a customer enrolls in the pilot program with an arrears balance of 8 \$250, they will need to contribute \$150 per month worth of prepay credits to their 9 PrePay account. The reason for this is that \$30 (20%) of the total prepayments each 10 month will go towards a reduction of their arrears balance, and \$120 will go towards 11 prepayment for their monthly consumption. This will allow the customer to pay 12 off their arrears balance in less than nine months. This scenario will differ for 13 different customers, some of whom will use above the average residential 14 consumption, and some of whom will use below the average consumption. The 15 Company will monitor the effectiveness and timing with which each PrePay Pilot 16 customer with arrears is able to pay down their outstanding balance. 17 18 4. Enrollment Incentive 19 The Company did not propose any kind of enrollment incentive or discounted rate 20 in its proposed PrePay program in U-21087. However, for this Pilot, the Company 21 will offer an enrollment incentive for customers who voluntarily enroll to 22 participate in this PrePay Pilot. This will include a \$15 PrePay account credit for 23 all pilot participants after three consecutive months on the pilot, plus an additional 24 \$20 credit for customers who stay on the pilot program for 12 consecutive months.

Line <u>No.</u>	U-21297
1	5. <u>Disconnection/Reconnection</u>
2	In the Company's request for approval of its proposed DTE PrePay program in U-
3	21087, it indicated that after a customer reaches a zero balance in their PrePay
4	account, they would be subject to shutoff no sooner than the next business day, but
5	would not be disconnected on weekends, holidays, or during extreme weather
6	events.
7	
8	For the proposed voluntary PrePay Pilot in the instant case, the Company, in
9	response to concerns raised about the automatic shutoff of customers within one
10	business day, is going to extend the time between reaching a zero balance, and when
11	the customer would be disconnected, to five calendar days, which for some
12	customers could be up to seven days, if the fifth day falls on a weekend or federal
13	holiday. Additionally, customers will be provided the opportunity to transition,
14	without penalty, back to post-pay billing at any time during this five-day window
15	– I will expand on this in a subsequent section of my testimony.
16	
17	6. <u>Reporting Requirements</u>
18	The Company, in its request for approval of its PrePay program in U-21087,
19	indicated that it would collaborate with MSPC Staff to determine which program
20	outcomes and metrics it would monitor and share, and at what frequency, to assess
21	the pilot program and to capture lessons learned. While a comprehensive list was
22	not provided by DTE in U-21087, the Company did provide examples of several
23	metrics it would recommend.
24	

1		For the proposed PrePay Pilot, the Company is committing to providing all of the
2		monthly data and reporting suggested by Intervenors in Case No. U-21087, and
3		supported by the Commission in its December 21, 2022, Case No. U-21087 Order.
4		The Company will also provide an annual and final report for the 2-year pilot, per
5		the Commission's recommendation in its December 21, 2022 Case No. U-21087
6		Order. A full list of the metrics that the Company will monitor and report can be
7		found in Exhibit A-24, Schedule N11 as part of the Company's objective utility
8		PrePay Pilot criteria submission.
9		
10	Q142.	Is DTE Energy able to make daily usage and cost information available to all
11		customers, as the Commission encouraged on page 17 of its December 21, 2022
12		order in Case No. U-21087?
13	A142.	Daily usage information is available for download to all customers with a DTE
14		online account and an active AMI meter. However, the AMI infrastructure and
15		billing system are not scaled or designed to perform daily bill calculations for 1.9
16		million DTE Electric customers. Also, it's important to note that prepaid billing is
17		more than just about showing customers what they used and how much it cost, it's
18		also about actively engaging them in them in the monitoring and control of their
19		usage, letting them decide how much and how frequently to pay. Additionally, the
20		Company has already invested in the technology to provide this information to all
21		customers through the DTE Insight App, which has to-date been downloaded by
22		~233,000 unique customers.
23		
24	Q143.	How will the information provided to PrePay Pilot participants, differ from
25		what is offered by DTE Insight?

1 A143. Customers who choose to engage in the use of the DTE Insight App, are provided 2 daily views of their electric usage, the estimated cost of that usage, and projected 3 bill amounts for their current bill cycle. While this does provide customers 4 additional insight into their usage and the cost of that usage, it does not put the 5 customer in control of when and how much they pay, it does not send push 6 notifications to customers informing them of when they are approaching a threshold 7 of usage, nor does it provide a mechanism for customers with arrears to 8 conveniently pay down that past due balance. Additionally, a customer's actual 9 next bill may be quite different than what is being estimated by the Insight App, 10 and therefore could still come as a surprise to the customer, and is something the 11 customer is asked to acknowledge when using the app, as shown in Figure 25.

- 12
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Figure 25

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15



**DTE Insight Usage and Cost Presentation** 

16

17 The PrePay Pilot solution considers all the daily charges as calculated by the 18 prepaid billing system, including taxes, and is able to provide the customer with a

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#### Line No

<u>No.</u>

1	meaningful estimate of the number of days of usage remaining. The customer can
2	use this information to make an informed decision about how much they are using,
3	how they might be able to reduce their usage, and how much to contribute to their
4	prepaid billing account, which ultimately is up to them and based on their
5	assessment of their own personal situation and needs.
6	
7	Customer Interest
8	Q144. Do any other utilities offer prepaid billing for their electric customers?
9	A144. While the vast majority of the active prepay programs are deployed at rural electric
10	cooperatives and municipal utilities, large utilities (e.g., SRP), and several Investor-
11	Owned Utilities (IOUs) have commercialized, or are currently piloting, prepay
12	offerings for their customers (Figure 26).
13	
14	Figure 26 Large Electric Utility Prepaid Billing Programs



15

# 16 Q145. What evidence is there that utility customers are interested in prepaid billing?

A145. In a 2019 consumer survey study completed by the Russell Research Group, it was
 concluded that interest in utility prepaid billing programs is high, especially in the
 18-34 year old age, where 50% of survey respondents indicated they would be

extremely interested, very interested, or interested in a voluntary prepaid billing program (Figure 27).

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### Figure 27 DEFG Prepaid Billing Interest Survey

6 This data is consistent with DTE's expectation that younger customers would be 7 more likely to enroll in PrePay pilot, and as such, the Company has decided to 8 exclude seniors from enrolling in the PrePay Pilot. The full results of the study, in 9 which consumers surveyed responded to a multitude of questions related to prepaid 10 utility service, is included in Exhibit A-24, Schedule N19.

11

# Q146. What reasons would an electric utility customer have for being interested in a prepaid billing program?

A146. The Company asserts that for customers who 1) want a tool that actively engages
them in monitoring and managing their usage, 2) want to better manage monthly
budgets by paying in in amounts they want and at a frequency that works for them,

Q.3. If your local utility or provider were to offer a voluntary prepaid option for consumers, how interested would you be?

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2	to avoid costly deposits and late fees, prepaid billing represents an attractive
3	voluntary alternative to traditional post-pay billing.
4	
5	This assertion is supported by industry studies, including the Russell Research
6	Group report included in Exhibit A-24, Schedule N19 (page 18) and a 2019 SRP
7	survey of its M-Power program participants, which indicates that a large percentage
8	of customers who enrolled in the program did so to gain more control over their
9	energy usage, to avoid security deposits, and to eliminate late fees. In that same
10	survey, SRP asked M-Power participants if they agreed or disagreed that prepaid
11	billing could help people reduce their energy usage and better manage their monthly
12	finances. Most customers either agreed, or strongly agreed, that prepay was
13	beneficial to customers, and that it would help those who enroll with their monthly
14	budgets. The results of this survey are provided in Figure 28.
15	
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and / or 3) struggle to stay current on traditional post-pay billing programs and want



9 customers?

10 A147. Yes. In December of 2020, the Company completed a small focus group, consisting 11 of 75-minute interviews with 28 customers, to gauge the ability of these customers

12 to understand how prepaid billing works, and how interested they would be in

1 enrolling in a voluntary DTE Electric prepaid billing program. Results were mixed, 2 but in general, customers grasped the concept of prepay and acknowledged the 3 benefits of being able to pay what they want, when they want, but some had 4 concerns about the level of engagement required to realize those benefits. 5 Additionally, a few customers in the panel who indicated they struggle with post-6 pay billing, indicated that they have learned how to maneuver the post-pay 7 collection processes to avoid shutoff for long periods of time, and that a prepaid 8 program would be less appealing to them. The full results of the focus group study 9 are provided in Exhibit A-24, Schedule N18.

10

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No.

# Q148. Can you expand on what types of customers the Company maintains might benefit from a prepaid billing program?

13 A148. We are designing our PrePay Pilot as a voluntary option for all eligible residential 14 customers regardless of their financial status, recognizing that different customer 15 segments have different needs and will benefit differently from enrollment in prepaid billing. The PrePay Pilot will provide all customers visibility and a greater 16 17 sense of control over the energy they use and how much they spend, the ability to 18 pay on a schedule that they establish and that better meets their needs, and a 19 simplified billing experience. For customers who struggle to stay current on today's 20 monthly post pay billing model, prepaid billing will provide them the opportunity 21 to pay in smaller amounts and at a frequency that aligns with their ability to pay, to 22 easily monitor their usage, and to conveniently have a portion of each payment they 23 make applied to the reduction of their arrears balance.

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I've provided below an overview of the case for change and anticipated customer benefits for four identified segments of customers. Within these segments are unique customer "personas", which are described in Exhibit A-24, Schedule N12, along with how enrollment in the PrePay Pilot would benefit customers in these segments who choose to enroll, and what they would experience during the enrollment process and while they are enrolled in the program.

7

8

### 1. <u>Tech Savvy Energy Conservers</u>

9 "Tech Savvy" customers tend to be younger and tend to have a greater desire to 10 look for ways to conserve energy and reduce their carbon footprint, as evidenced by the over  $\sim 233,000$  unique customers who have downloaded the DTE Insight 11 12 App, and the ~80,000 residential customers who have enrolled in the Company's 13 Michigan Green Power (MIGP) programs, with enrollments among the 18-39 year 14 age group significantly increasing over the last several years. The PrePay Pilot will 15 provide an additional option for this segment of customers to further engage in how 16 much electricity they are using, to make payments based on their needs and when 17 it's convenient for them, and to further reduce their usage and carbon footprint.

18

19

### 2. Financially Stable Savers

20 Many customers are financially stable and don't have issues paying their bills, but 21 they do pay attention to, and look for ways to more effectively manage, their 22 monthly expenses. Of the total volume of Billing calls received every year, it is 23 estimated that up to 15% are from customers who repeatedly call to inquire about 24 their bill, often times because they are questioning the usage and/or the amount of 25 the bill. While the Company has trained CRs to handle these inquiries and address

### No. 1 customer questions and concerns, these conversations can leave some customers 2 still confused, still frustrated, and still with the perception that their bill is incorrect. 3 4 Customers who repeatedly question the usage shown on their bill, or who are often 5 surprised by the amount of their bill, could benefit from enrollment in the PrePay 6 Pilot because it would simplify their billing experience, put them in control of the 7 energy they use and how much they spend each month, and eliminate monthly high 8 bill surprises. 9 10 3. <u>Renters and College Students</u> 11 For renters and college students, prepaid billing offers several benefits. These 12 customers tend to move more frequently than typical residential customers. The 13 PrePay Pilot would eliminate the need for complicated ID validations and document 14 submissions, with customers simply required to provide their name, a phone 15 number, and a valid email address. Additionally, for renters and college students 16 with roommates, prepaid billing provides easy visibility into how much energy is 17 being used each day and what they are spending, allowing roommates to discuss 18 the importance of watching their energy usage to reduce shared monthly expenses. 19 For parents of college students, the PrePay Pilot will provide the ability to actively 20 monitor their college student's usage and work together to minimize monthly utility 21 expenses. 22 23 4. Payment Troubled and Vulnerable Customers 24 Many lower-income customers "live in the financial moment" and may struggle 25 with traditional post-pay monthly billing due to a lack of financial stability and

inconsistencies in their income streams. Additionally, some customers who may
not necessarily struggle this way financially, can find themselves in financially
troubled situations due to circumstances beyond their control, such as the
unexpected loss of income. Regardless of the circumstance, customers who find
themselves financially struggling experience significant stress, often wait until the
last minute to pay, often pay late, can accumulate large arrears balances, and can
find themselves disconnected for non-payment.

8

9 While the Company provides support to these customers through access to agency 10 funding and a variety of payment plan options, not all customers qualify for energy 11 assistance or enrollment in a plan. Those who do qualify experience varying levels 12 of success depending on the amount owed, the plan in which they are enrolled, and 13 their ability to consistently pay their plan amount and their current month's usage. 14 Late fees and the added costs of deposits and reconnect charges put additional stress 15 on these customers, many of whom are stuck in a repeated cycle of disconnects and 16 reconnects, and who have to make tough choices about which monthly bills get 17 paid, and which ones don't.

18

19 The PrePay Pilot will be another tool for the Company and its Customer 20 Representatives (CRs) to assist customers for whom traditional billing and payment 21 plans do not work, allowing this segment of customers to take more control and 22 responsibility for the energy they use, to decide when and how much they pay based 23 on their financial situation and anticipated usage patterns, and to avoid the stress 24 that comes with receiving a monthly bills that they cannot afford.

# Q149. Will the Company market its PrePay Pilot to customers who have a pending shutoff or that have been disconnected for nonpayment?

A149. The Company has designed its PrePay Pilot as a voluntary option for eligible
customers and will not market the program to any particular segment of customers.
Instead, the Company is training its CRs to be able to determine, based on a
customer's unique situation, if prepaid billing might be a viable option for that
customer.

8

9 For customers who have a pending shutoff, or have been disconnected for 10 nonpayment, enrollment in the PrePay Pilot could be an attractive alternative that 11 allows them to avoid shutoff, or to reconnect service more easily and avoid the 12 added stress of having to find a large amount of money to pay a portion of their past 13 due balance, a deposit, and a reconnect fee. While disconnected customers who 14 choose to enroll in the PrePay Pilot may need to pay down the portion of their 15 arrears that exceeds \$250, the Company will waive the normal deposits and 16 reconnect fees.

17

For low-income customers who find themselves in these situations, the CRs will confirm the customer's low-income eligibility, determine what agency assistance is available for these customers, determine their eligibility for payment programs such as LSP or PSP, and then determine if the PrePay Pilot is a viable solution for these customers. Ultimately, the customer will decide if they want to enroll.

1	PrePa	y Pilot Customer Benefits
2	Q150.	Has the Company assessed the potential value of prepaid billing for program
3		participants?
4	A150.	Yes. Several studies support the conclusion that electric utility customers who
5		participate in a prepaid billing program realize significant reductions in usage.
6		According to a 2018 report by the American Council for an Energy Efficient
7		Economy (ACEEE), customers who participate in a prepay program reduce their
8		energy usage by 9% on average, which is within the range of prior ESource studies
9		that concluded customers enrolled in a prepay program realize energy reductions
10		of 5-14%. And Salt River Project (SRP), the largest provider of prepaid electricity
11		in the United States, has indicated that on average, customers on its prepaid M-
12		Power program reduce their energy usage by 12%.
13		
14	Q151.	How does the Company know that the reductions in usage cited in these
15		studies, and by other utilities, aren't the result of energy "starvation"?
16	A151.	This is a common concern voiced by consumer advocacy groups regarding prepaid
17		utility service, who cite the uncertainty regarding how much of the realized usage
18		reductions, identified in studies of electric prepaid billing, are from positive
19		changes in customer behaviors versus how much is from customers being
20		repeatedly disconnected, or from customers who "starve" themselves of energy or
21		that simply choose to go without power for extended periods of time.
22		
22		
22		To the Company's knowledge, there are no comprehensive studies that support, or
22 23 24		To the Company's knowledge, there are no comprehensive studies that support, or refute, the concerns of consumer advocates. However, the previously referenced

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disconnecting" by letting their account balance fall below zero and reconnecting at
their convenience. Of the consumers that responded to this question, 28% said they
would consider self-disconnecting to meet their needs (Exhibit A-24, Schedule
N19, Page 33). and the Company has no insight into the behavior of customers
included in these studies. As such the Company acknowledges that for some
customers who voluntarily enroll in the program, some might purposely allow the
service to be disconnected if it suits their needs.

8

9 While the Company has no additional insight into how customers who are actually 10 enrolled in a prepaid utility billing program behave, it can say that it is not its 11 intention to use prepaid billing as an opportunity to repeatedly disconnect 12 customers, or to provide customers a tool they can use to "starve" themselves of 13 energy. The Company's intention is to give customers a voluntary billing option 14 that provides them the tools and information they need to make informed decisions 15 of what they are using, how much it cost them, what they expect to us, and how 16 much they might want to contribute to their account with each prepayment.

17

18 Should the Company receive approval for its proposed PrePay Pilot, it will measure 19 customer electric usage, and to the extent possible gather the data and feedback 20 from customers, through a quarterly survey of PrePay Pilot participants, to 21 determine the nature of any realized usage reductions.

22

Q152. Has the Company assessed the value of usage reductions in the range of what
 is provided in studies of other prepaid electric utility billing programs would
 mean for its customers who choose to enroll in the PrePay Pilot?

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No.

1	A152.	Yes. In 2022, the average monthly usage for a residential DTE Electric customer
2		was ~625kWh, and average total bill amounts for these customers was ~\$120.
3		Therefore, for the average customer who chooses to enroll in the PrePay Pilot, a
4		10% reduction in usage would provide savings of approximately \$12 per month
5		(\$144 per year). The actual savings realized will of course depend on the
6		customer's actual (could be higher or lower than 625kWh per month) and their level
7		of engagement in using prepaid billing to actively monitor their usage and to take
8		actions that lower their consumption.
9		
10	Q153.	Are the forecasted monthly savings, as described in your response to the last
11		question, based on the rate schedule that the Company is proposing for the
12		PrePay Pilot?
13	A153.	Yes. The potential monthly savings are based on the assumption that PrePay Pilot
14		participants will be on the Company's D1 Non-Transmitting Meter rate.
15		
16	Q154.	Why is the Company proposing that PrePay Pilot customers be on the D1 Non-
17		Transmitting Meter rate?
18	A154.	In its originally proposed DTE PrePay program in Case No. U-21087, the Company
19		recommended that PrePay customers remain on the D1 Residential Service Rate
20		schedule, because at the time of the filing of Case No. U-21087 (September 29th,
21		2021), the final design, and implementation date, for the Company's Time-of-Use
22		(TOU) electric rate was still uncertain. As such, the expectation was that DTE
23		PrePay would be implemented before TOU, and that the Company would determine
24		the appropriateness of transitioning DTE PrePay customers to the TOU rate

Line <u>No.</u>	M. J. HATSIOS U-21297
1	concurrent with the implementation of Phase 2 of the program (Case No. U-21087,
2	Witness Hatsios, Page 13 Lines 9-25, Page 14 Lines 1-3).
3	
4	With the now pending 2023 implementation of Time-of-Day (TOD) – formerly
5	TOU - electric rates for DTE Electric residential customers, the Company has
6	revisited TOD for the proposed PrePay Pilot and has concluded that 1) the
7	incremental capital cost associated with redesigning the already deployed DTE
8	PrePay solution to support TOD rates for the pilot is cost prohibitive, 2)
9	incorporating TOD rates would unnecessarily delay the launch of the pilot, and 3)
10	TOD has the potential to complicate the experience for customers, both in terms of
11	the customers' ability to determine how their pattern of usage might impact the
12	amount and frequency of their prepayment, and in terms of the presentation of daily
13	usage and days remaining to PrePay Pilot customers.
14	
15	For these reasons, and the fact that this is an initial Pilot impacting no more than up
16	to 5,000 customers, the Company is proposing that PrePay Pilot customers be
17	placed on the D1 Non-Transmitting Meter rate that is being made available to non-
18	AMI electric customers who are not being transitioned to TOD. As the pilot
19	progresses, the Company will continue to assess the reasonableness and benefits of
20	implementing TOD as part of any approved expansion of PrePay upon the
21	successful completion of the pilot program. Company Witness Willis is sponsoring
22	the necessary changes to the Company's electric rate book.
23	
24	Q155. Has the Company assessed the impact to ratepayers of the implementation of
25	a prepaid billing program?

A155. Yes. Should the Company receive approval of its proposed PrePay Pilot and should
 the results of the pilot achieve its intended outcomes (as described in Exhibit A-12,
 Schedule N11), the Company would seek approval from the Commission to scale

the program into a permanent voluntary offering to expand the number of customers enrolled.

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7 The Company has forecasted that for every 10,000 DTE Electric customers it 8 enrolls in an expanded PrePay program, it would realize a reduction of over 9 \$108,000 in UCX, and it would reduce the cost of its working capital by over 10 \$97,000 per year. These savings assume that a mix of customers segments enroll 11 in the program (customers with and without arrears), – that the average arrears 12 balance is \$150 per customer, and that the Company's annual cost of working 13 capital is 6.50%. These savings would be passed on to customers through the 14 ratemaking process in future DTE Electric rate case filings, and would become 15 more substantial with each incremental enrollment of 10,000 customers (Table 3).

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- 17

Table 3Forecasted PrePay Ratepayer Savings

	Residential Electric Data - As of 02/01/2023			
	Electric Only Customers	Uncollectible Expanse (UCX)	Accounts Receivable	Working Capital Cost
Electric Only	1,311,481	14,188,156	196,781,580	12,790,802
\$ Per Customer		10.82	150.05	9.75
Per 10,000 Customers	10,000	\$ 108,184	\$ 1,500,453	\$ 97,529

18

Q156. What evidence does the Company have that prepaid billing reduces arrears
 for customers enrolled in an electric utility prepaid program?

1 A156. A key attribute of a prepaid billing program, and one that is universally included in 2 the available utility programs, is the ability of customers to apply a percentage of 3 each prepayment (typically around 20-25%) towards their arrears balance. Georgia 4 Power has indicated that during the first six years of their prepay program, 5 customers applied over \$24 million in prepayments towards a reduction in their 6 arrears balance. Also, a recent study by Exceleron, the largest provider of prepay 7 billing solutions for cooperative and municipal utilities, analyzed data for four 8 utilities using their prepay solution, and found that on average 31% of enrolled 9 customers participated in this debt recovery and reduced their arrears by on average 10 72% while on the program.

11

# Q157. What other benefits does the Voluntary Prepay Program option provide to customers?

14 A157. For new customers that have no prior history with the Company (e.g., first time 15 homeowner or moving from a different service territory), starting service by 16 enrolling in the PrePay Pilot will be much easier than it is with a traditional post-17 pay billing. While CRs will continue to ask these customers for the last four digits 18 of their social security number or a government issued photo ID, if the customer 19 indicates they do not wish to provide that information, the CRs will have the ability 20 to waive that requirement and the associated Experian validation of that customer's 21 identity. PrePay Pilot participants will still need to provide their date-of-birth 22 (DOB), a contact phone number, and a valid email address. The Company will 23 monitor the behavior of customers who request to enroll in the pilot to assess the 24 frequency with which they choose to not provide identifying information.

### 1 **PrePay Pilot Design**

# Q158. What industry learnings, and learnings from other utility prepaid billing providers, to inform the design of its proposed PrePay Pilot?

4 A158. The Company has been in contact with Salt River Project (SRP), Georgia Power, 5 and Duke Energy to discuss their experiences with prepaid billing and is a 6 participating member of the Prepay Energy Working Group (PEWG), a consortium 7 of industry professionals who share learnings and discuss the opportunities and 8 challenges associated with prepay billing programs. The Company has also 9 leveraged lessons learned from its own "Pay As You Go" pilot, which was offered 10 to DTE Electric customers from 2011 through mid-2015, and has discussed with Consumers Energy their experience with their "Pay My Way" prepay program, 11 12 which was offered to their customers from 2016 through June 2020. The Company 13 has incorporated lessons learned from other utilities, and its own experience with 14 prepay, into the design of its PrePay Pilot, which are summarized here:

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		• Make the program simple and easy for customers to manage, providing 24./7 online access for their account balance and payment history.
		• Provide 24/7 access to web and mobile payment channels – on average customers make 3-5 payments per month.
		• Allow customers to select the frequency of balance notifications in their preferred communication channel.
		• Ensure notification balances are consistent with what customers see in their online prepay account.
		• Provide customers the ability to allocate a percent of each payment to the reduction of their arrears balance.
1		
2	Q159.	Can you expand on the structure and
3		PrePay Pilot?
4	A159.	Yes. While I've already provided some
5		will provide here a complete summary of

- Provide the option for customers to set up an "auto-reload" option that automatically adds credits to their account at a frequency of their choosing.
- For customers who have been shutoff for nonpayment and wish to enroll in prepay, all deposit and reconnect fees are waived.
- Initially, enrollments should be managed through the contact center, leveraging CRs to ensure customers understand program requirements.
- Initially, limit enrollment to a subset of customers to avoid overcomplicating the experience – expand eligibility as the program continues to scale.

Line

### mechanics of the Company's proposed

4	A159. Yes. While I've already provided some of these details in my response to Q141, I
5	will provide here a complete summary of key PrePay Pilot design attributes across
6	six categories of the customer experience:
7	

- 8 1. Eligibility
- 9 For participation in the voluntary DTE PrePay Pilot, an "eligible customer" is defined as residential, being provided service through the Company's D1 Non-10 11 Transmitting Meter Rate schedule, with a single electric commodity (DTE Gas 12 customers are not eligible) and having an active AMI meter with remote connection
1 and disconnection capability. Customers with past due balances (e.g. electric 2 arrears) will be eligible to enroll, but can only do so up to a maximum of \$250 in 3 arrears, which will be reduced over time through the allocation of a portion of each 4 prepayment made by the customer, which I describe in more detail under the 5 "Enrollment" and "Account Management & Notifications" sections of my response 6 to this question. Other restrictions on eligibility are as I previously described in my 7 response to Q141. 8 9 2. Enrollment 10 Enrollment of customers in the voluntary PrePay Pilot will be exclusively over the 11 phone with a CR. While there will be information related to pilot on the DTE 12 website, it will be limited to basic program information, contact information, links 13 to Terms and Conditions (Exhibit A-24, Schedule N13), and a list of FAQs (Exhibit 14 A-24, Schedule N14). The website will include a dedicated phone number for 15 interested customers, whose calls will be directed to dedicated and specially trained 16 teams of CRs who can best answer their questions and manage the enrollment. Customers will be informed of their rights and responsibilities under the program, 17 18 including their waiving of the right to receive written (i.e. USPS mail) 19 communications and live agent phone calls ahead of a scheduled disconnect, which 20 I will discuss in more detail in my discussion of the Company's requested voluntary 21 PrePay Pilot billing rule waivers. Customers will be required to provide a valid 22 email address for the purposes of receiving enrollment information and a copy of 23 the full program terms and conditions, and to serve as their primary means of 24 receiving balance alerts and other notifications. However, all customers will have

the option of opting-in to SMS/text alerts, with customers who select this option receiving both email and SMS/text notifications.

- 4 Customers who choose to enroll in the PrePay Pilot, will be asked to make an initial 5 credit deposit of \$40 at the time of enrollment, which for the average customer 6 without arrears would provide  $\sim 10$  days of future consumption. In the case of 7 customers with arrears who choose to roll over a past due balance, 80% will go 8 towards their future consumption and 20% will be applied to any past due balance 9 through the PrePay Deferred Payment Plan (DPP), with customers able to rollover 10 a total of \$250 in past due balances into the DPP. Customers will also be provided 11 the option to include in the DPP any current bill amounts due, however, the total 12 rollover cannot exceed \$250. Exhibit A-24, Schedule N15, provides a view of the 13 PrePay Pilot enrollment process. Please note, the provided exhibit may not be 14 reflective of everything described here - for example, it does not include 15 communication to the customer of the previously discussed \$15 and \$20 three 16 month and 12 month program incentive.
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#### 3. Account Management & Notifications

After enrollment, customers will be able to view the estimated daily usage amount for their premise in both kWh and dollars, along with the number of days of estimated usage remaining, on the DTE website, on their mobile web device, via the automated phone system (IVR), or through a request to a CR. Customers will also receive low balance notifications through email, and optionally SMS/text. messages, at ten, five, three and one day prior to reaching a zero balance. Additionally, if desired, customers can sign up for daily balance notifications.

2 Customers enrolled in the PrePay Pilot will be able to make minimum one-time 3 payments of \$10 through a DTE CR, on the DTE website, in the Mobile App, in 4 the IVR, or at a Kiosk, with these payments posting in real-time to their PrePay 5 account. While customers can continue to make payments through an Authorized 6 Pay Agent (APA), or via U.S. mail, these methods of payments are not 7 recommended due to the inherent delays between when the payment is made and 8 when it would be posted to a customer's PrePay account. Future dated payments 9 can be scheduled through a DTE CR in the same manner as they are today, with 10 customers also offered the ability to set up auto reload of prepay credits in an 11 amount and at a threshold of days remaining that they choose.

12

13 Customers who enroll in the PrePay Pilot on the DPP, will have 20% of each 14 payment they make applied to their past due balance, with the remaining 80% put 15 towards future consumption. Exhibit A-12, Schedule N16 summarize the customer 16 Account Management & Notification experience, which includes what they will 17 see when they log into their account, how they can enroll in optional SMS/text 18 messages, how they make payments and enroll in auto reload, and what they will 19 be provided in the low balance alerts. Please note, the provided exhibits may not 20 be reflective of everything described here – for example the Company will be 21 adding a 10 day alert and will add links to energy assistance information and PrePay 22 CR contact information to the 5 day and 3 day alerts, similar to what is reflected in 23 the exhibit for the 1-day alert.

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4. Disconnection/Reconnection

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Upon reaching or falling below a zero credit balance, PrePay Pilot customers will be informed that they are scheduled for disconnect, along with the scheduled date of disconnect. By this time, a PrePay Pilot customer will have already received the previously described 10, five, three, and one day low balance notifications, which provides them ample time to replenish the account prior to reaching a zero balance.

For customers who reach a zero balance, disconnects will occur no sooner than five
calendar days later, and the customer will be provided confirmation of the shutoff
along with what is required to reconnect service if they are disconnected.
Disconnects will only occur Monday-Friday 8:00 a.m. until 6:00 p.m., will not occur
on weekends or federal holidays, and will be deferred during storm and other
extreme weather events.

13

14 Customers disconnected for non-payment can be reconnected by making a payment 15 for any outstanding unpaid usage plus a minimum payment of \$40, which will be 16 applied to their account as credit towards their future energy consumption. 17 Customer reconnection requests will be submitted to their AMI meter in real-time 18 with an average processing and reconnection time of 30 minutes after payment is 19 received. However, depending on the circumstances, reconnect may take up to four 20 hours. After seven days, if the customer has not made payment to reconnect service, 21 they will be notified that to reconnect they must contact a DTE CR, and after 30 22 days of nonpayment the customer's account will be permanently closed.

23

All PrePay Pilot customers will have the option at any time before or after reaching
a zero balance to unenroll from the program and return to post-pay billing without

1 penalty. Customers will only be disconnected after five calendar days if they do 2 not replenish their account and do not request to be reverted to post-pay. Exhibit 3 A-12, Schedule N17 provides a summary of what PrePay Pilot customers will 4 experience when they reach a zero balance and when they are disconnected. Again, 5 please note, the provided exhibit may not be reflective of the disconnect 6 notifications that will be provided to PrePay Pilot customers – for example, the 7 Company will update the communications for customers who reach zero balance to 8 include daily reminders that to avoid a disconnection of service they either need to 9 replenish their PrePay account or need to contact the Company to revert to post-10 pay billing.

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#### 12 5. <u>Customer Feedback</u>

As previously stated, the Company is agreeing to track on a monthly basis the data proposed by the Intervenors in Case No. U-21087, and supported by the Commission in its December 21st, 2022 Case No. U-21087 Order. Additionally, the Company intends to administer a quarterly email and/or phone survey of PrePay Pilot participants to assess their level of satisfaction for the program, and to capture from them opportunities for improvement.

19

#### 20 6. <u>Unenroll</u>

Customers enrolled in the PrePay Pilot may unenroll from the program at any time. A customer who unenrolls from PrePay and elects to continue receiving energy from DTE will be returned to post-pay billing. A customer who chooses to unenroll from the PrePay Pilot will not be penalized with additional fees but will be responsible for the payment of any unpaid usage and past due balances, and will be

Line <u>No.</u>	M. J. HATSIOS U-21297
1	subject to the same Experian identify validation checks and deposit rules as any
2	other non-prepay customer.
3	
4	Q160. Will eligible low-income customers continue to be able to access agency
5	assistance while on the PrePay Pilot?
6	A160. Yes. Low-income customers who want to enroll in the PrePay Pilot, and who are
7	eligible for energy assistance, will be provided all of the support available from the
8	Company and its agency partners to access and receive that assistance. The process
9	for requesting and receiving assistance dollars will not change, with the dollars
10	credited to the customer's PrePay account according to applicable agency rules and
11	policies. In general, the dollars received will be used to pay down any past due
12	balance - in the same manner as agency assistance is applied to a post-pay
13	customers account – and when allowed by the agency providing the assistance, any
14	remaining dollars will be applied to their PrePay credit balance to pay for future
15	consumption.
16	
17	PrePay Waivers
18	Q161. Is the Company asking for any waivers of the MPSC's Billing Practice Rules
19	to implement Prepay?
20	A161. Yes, the implementation of the PrePay Pilot will require the MPSC to waive several
21	billing practice rules. Below I identify the rules DTE is requesting a waiver of, an
22	explanation of why the Company believes a waiver is necessary and if PrePay offers
23	alternatives that fulfill the purpose of the rule.
24	
25	<u>460.120 (3) Rule 20 (3)</u>

Line No.	M. J. HATSIOS U-21297
1	A bill shall be mailed, transmitted, or delivered to the customer not less than
2	21 days before the due date. Failure to receive a bill properly mailed,
3	transmitted, or delivered by the utility does not extend the due date.
4	
5	Reason for Waiver/Alternative
6	Prepay customers will not receive a bill so this rule has no applicability to PrePay
7	customers. Prepay customers are able to check their daily usage, prepayments
8	made, and number of estimated days of usage remaining in their online account
9	24/7. Additionally, PrePay customers will be provided notification that a monthly
10	summary of their account activity is ready for review, along with a link to that
11	summary, which for a PrePay customer with arrears will include the amounts of
12	their prepayments that were applied to those arrears and their current arrears
13	balance.
14	
15	<u>460.129 (4) Rule 29 (4)</u>
16	When a residential customer receives a past-due notice from the utility, the
17	utility shall provide the customer access to information about energy
18	assistance programs referenced in sub rules (1) and (3) of this rule, which
19	shall, at minimum, include a telephone number of a utility representative
20	able to provide this information.
21	
22	Reason for Waiver/Alternative
23	PrePay customers will not receive a past-due notice so this rule would have no
24	applicability to PrePay customers. However, communications via text, e-mail and
25	on the Company's PrePay web site page will provide a link and phone number and

Line <u>No.</u>	<b>M. J. HATSIOS</b> U-21297
1	the information will be included in the 10, 5, 3, 1 and 0 day text or e-mail messages
2	which performs the same purpose as this rule. Also, customers will also receive a
3	phone number to a specialized PrePay team.
4	
5	<u>460.139 (1) Rule 39 (1)</u>
6	Not less than 10 days before the proposed shut off of service, pursuant to
7	the provisions of R 460.140, R 460.142 and R 460.143 of these rules, a
8	utility shall send a notice to the customer by first-class mail, or personal
9	service.
10	
11	Reason for Waiver/Alternative
12	DTE Electric will not be sending notices to PrePay customers via first-class mail
13	or personal service. As a part of the PrePay program, a customer will specify what
14	type of electronic communication they prefer and will receive a notice of shut off,
15	compliant with R460.140 Rule 40, at 10, 5, 3, 1, and 0 days before their balance
16	runs out and they become eligible for shut off.
17	
18	<u>460.139 (6) Rule 39 (6)</u>
19	For an involuntary shutoff, at least 1 day before shutoff of service, the utility
20	shall make no less than 2 attempts to contact the customer by telephone, if
21	a telephone number is available to the utility, to advise the customer of the
22	shutoff and what steps the customer must take to avoid shutoff. If the utility
23	uses an automated notification system, it shall document the process for
24	ensuring that at least 2 attempts are made to notify the customer of the
25	pending shutoff. If the telephone number is not available, the customer has

no telephone, or the utility chooses not to make telephone contacts, the
utility shall either leave a notice at the premises advising the customer that
service will be shutoff on or after the next business day or send notice by
first-class mail postmarked at least 5 business days before shutoff of service
is scheduled. The utility shall document all attempts to contact the
customer. The 10-day notice sent under subsections (1) or (5) of this rule
shall be considered as 1 attempt.

8

9

#### Reason for Waiver/Alternative

By participating in the PrePay program, customers agree to receive all communications via email or other electronic contact. PrePay customers have decided to play an active role in their energy usage and will be getting more communication around what their balance is and how long it is likely to provide them with service. In addition, the PrePay standard messaging will provide low balance and shut off warnings, including a link to the notice of shutoff including the information required in 460.140 Rule 40, at 10, 5, 3, 1, and 0 days of shutoff.

17

#### 18 460.143 (1) Rule 43 (1)

For an involuntary shutoff of service using meters with remote shutoff and restoration capability, at least 1 day before shutoff of service, the utility shall make at least 2 attempts to contact the customer by 1 of the methods listed in R 460.139(6) of these rules. The notice shall conspicuously state that the disconnection of service will be done remotely and that a utility representative will not return to the premises before disconnection.

25

Line No.		M. J. HATSIOS U-21297
1		Reason for Waiver/Alternative
2		This notification will be via text or email.
3		
4	Q162.	Are these the same waivers requested in Case No. U-21087?
5	A162.	No. The waivers requested have been minimized as much as possible to address
6		intervenors' concerns regarding potential harms from the waivers requested in U-
7		21087. These waivers do not include notice of shut off requirements. Under the
8		current proposal, DTE will provide all the information required by the billing rules
9		prior to shut off, unless specifically mentioned above. Additionally, the timelines
10		for such notice will be adhered to. The main purpose of the waivers is to allow all
11		notifications to be allowed via links in e-mails and text communication.
12		
13	Q163.	How are customers on Prepay provided similar protections in the absence of
14		the above MPSC billing rules?
15	A163.	The protections provided by the billing rules for which the Company is requesting
16		waivers, are necessary in the post-pay model to help ensure customers are provided
17		adequate opportunity to access funding, and if necessary, enroll in a payment plan
18		to avoid shutoff. While this process plays out, today's post-pay customers continue
19		to consume energy, adding to both their past due balance and their current amount
20		due. For some customers, this cycle continues, over and over again, and still
21		ultimately results in the disconnection of service for nonpayment.
22		
23		The prepay model flips the script and gives customers who enroll in PrePay the
24		opportunity to pay what they want, when they want, based on their financial
25		situation and their energy needs. To assist customers, and to ensure they can

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successfully maintain a credit balance and avoid being disconnected, the Company will provide relevant information to the customer in the form of the previously described daily balance updates, low balance alerts, and easy payment options, which includes notifications letting the customer know that they can contact DTE for assistance if necessary to avoid shutoff.

6

7 Additionally, as described in the previously discussed PrePay Pilot eligibility 8 requirements, the Company is excluding customers with a medical emergency at 9 the premise, those with active military service, and any senior customers. Also, as 10 described, the Company is adhering to the same disconnect rules that are in place 11 today for post-pay customers (i.e. no shutoffs on weekends, or holidays, or during 12 extreme weather). And finally, as I indicated, the PrePay Pilot is an optional 13 program, customers can transition out of PrePay at any time with no penalty if they 14 determine that the program is not providing them the benefits that they expected.

15

#### 16 Part 11. Historical 2021 Project Spend Variance

Q164. How much did the Company spend in 2021 on total IT capital projects
compared to what the Commission authorized for inclusion in rates in Case
No. U-20836?

A164. The Company spent \$158.4 million of capital on IT projects in 2021 compared to
the \$121.8 million approved by the Commission in Case No U-20836, as shown in
line 1 of Exhibit A-24 Schedule N2, which is \$36.6 million more than was
approved.

24

#### 1 Q165. Was there a variance in the Customer Service IT Portfolio for the projects for 2 which you provided testimony? 3 A165. Yes, for projects that I support, there is a variance of \$6.7 million between what 4 was approved in Case No. U-20836 and what was spent. This variance is associated 5 with only one project: Prepay. As previously discussed in my testimony, this 6 project was disallowed by the Commission on the basis that an order approving the 7 program and the associated Billing Rule waivers which were requested in Case No. 8 U-21087 had not yet been approved. 9 10 Q166. Does this complete your direct testimony?

11 A166. Yes, it does.

#### STATE OF MICHIGAN

#### BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)
DTE ELECTRIC COMPANY	)
for authority to increase its rates, amend	)
its rate schedules and rules governing the	)
distribution and supply of electric energy, and	)
for miscellaneous accounting authority.	)

Case No. U-21297

#### QUALIFICATIONS

#### AND

#### DIRECT TESTIMONY

#### OF

#### BRIAN L. HILL

#### DTE ELECTRIC COMPANY QUALIFICATIONS AND DIRECT TESTIMONY OF BRIAN L. HILL

Line <u>No.</u>

1	Q1.	What is your name, business address and by whom are you employed?						
2	A1.	My name is Brian L. Hill (he, his, him), and my business address is One Energy						
3		Plaza, Detroit, Michigan, 48226 and I am employed by DTE Electric Company						
4		(DTE Electric or Company).						
5								
6	Q2.	On whose behalf are you testifying?						
7	A2.	I am testifying on behalf of DTE Electric.						
8								
9	Q3.	What is your educational background?						
10	A3.	I graduated from Michigan State University Eli Broad College of Business. I						
11		graduated with a Bachelor of Arts Degree in Materials & Logistics Management						
12		with a focus on Operations Management. I received a Juris Doctorate (JD) Degree						
13		from the University of Detroit Mercy School of Law. I have also completed several						
14		Company sponsored courses and attended various seminars to further my						
15		professional development including Lean Six Sigma Certification.						
16								
17	Q4.	Please summarize your professional experience.						
18	A4.	I began my career in the automotive industry working for Johnson Controls; a						
19		world-wide Tier 1 OEM supplier. I worked there from 1994-2008 where I held a						
20		series of positions in materials, operations, and plant management. In my plant						
21		manager role, I was responsible for all aspects of the business including safety,						
22		operations, engineering, quality, materials, finance/accounting, continuous						
23		improvement, and human resources. The plant employed approximately 400						
24		people comprised of both salary and UAW union members. My employment with						
25		DTE began in October 2008 as the Logistics Manager in Energy Supply. Between BLH-1						

Line <u>No.</u>

1	January 2011 and November 2012, I was the Senior Supply Chain Manager at the
2	Fermi 2 Nuclear Power Station where I held responsibility for warehousing,
3	procurement, contracts, and work management. These activities were essential to
4	supporting safe, reliable, and efficient plant operations including refueling outages.
5	Between December 2012 and March 2015, I was a Director in Corporate Services
6	where I held increasing leadership responsibility in the Center of Excellence,
7	Supplier Performance Management, and Facilities Operations. In this role I was
8	responsible for strategic planning, operational metric reporting, safety strategy,
9	resource planning, financial forecasting, and continuous improvement. I was also
10	responsible for the long-term and daily operations of facilities management,
11	including asset management. Between April 2015 and October 2016, I was the
12	Director of Tree Trimming in the Distribution Operations organization of DTE
13	Electric. In this role I was responsible for leading the strategic development and
14	implementation of the Enhanced Tree Trim Program. In addition, I was responsible
15	for Tree Trim Operations, comprised of DTE Energy Employees and tree trim
16	contractors (comprising over 500 employees in 2016). In this role, I was responsible
17	for safety, quality, productivity, customer satisfaction, storm and trouble restoration
18	efforts, and relationships with municipalities. In November 2016 I started my
19	current role, as the Director of Scheduling and Construction in the Distribution
20	Operations organization of DTE Electric.

21

## Q5. Do you hold any certifications or are you a member of any professional organizations?

A5. Yes. I am a Licensed Attorney in the State of Michigan and a Lean Six SigmaBlack Belt.

1		
2	Q6.	What are your current duties and responsibilities?
3	A6.	My responsibilities as Director of Scheduling & Construction include six primary
4		areas: 1). Overhead & Underground Scheduling 2). Substations Planning &
5		Scheduling 3). Work Management 4). Logistics & Contract Management 5).
6		Billing, Unitization, and Inspection 6). Safety, Human Performance, Hazardous
7		Energy Control. I also was responsible for the Project Management Office from
8		November 2016 until June 2022 where I managed a large portfolio of projects and
9		programs for Distribution Operations that included planning and construction.
10		These organizations are briefly described below:
11		
12		Overhead & Underground Scheduling: This organization schedules all planned
13		work for both DTE and contractors' field crews on overhead and underground
14		distribution assets.
15		
16		Substations Planning & Scheduling: This organization plans and schedules all
17		work for both DTE and contractors' field crews on substations. The team also
18		includes field contractor oversight for substation builds and modifications.
19		
20		Work Management: This organization leads systematic approaches to track and
21		measure work, streamline business processes and routine tasks. The team governs
22		the Maximo Business Process that coordinates team collaboration and workflows
23		across all levels of the organization.

1 Logistics & Contract Management: This organization facilitates and oversees 2 contractor field resources (approximately 750-800 field workers). The team is 3 responsible for contract management and supplier performance management. The 4 team also leads the planning, mobilization, and field oversight of out-of-state storm 5 resources when required for large severe weather events. 6 7 Billing, Unitization, and Inspection: This team is responsible for contractor 8 accounts payable & invoicing, unitization of capital investments, and conducting 9 field quality inspections to validate construction is built to standards and 10 specifications. 11 12 Safety, Human Performance, Hazardous Energy Control: This team includes 13 subject matter experts (SME's) in the areas of electrical safety, human performance, 14 and hazardous energy control (red tag/lock out tag out). The SME's are responsible for and govern procedures, training, and governance of these safety programs. 15 16 17 Q7. Have you previously sponsored testimony before the Michigan Public Service 18 **Commission (MPSC or Commission)?** A7. 19 No. I did support witness testimony related to the enhanced tree trimming program 20 in prior rate cases. 21

#### 1 **Purpose of Testimony**

2	<b>Q8.</b>	What is the purpose of your testimony?				
3	A8.	As referenced in Witness Robinson's description of the distribution witnesses, my				
4		testimony s	supports, as rease	onable and necessary, the historical capital expenditures		
5		and propos	sed capital expe	enditures related to base capital programs (emergent		
6		replacemer	nts, customer co	nnections, relocations, and others). In addition, I will		
7		support se	elect strategic o	capital expenditures related to the technology and		
8		automation	projects and dis	scuss 4.8kV Circuit Automation metrics associated with		
9		the Compa	ny's proposed D	Distribution Infrastructure Recovery Mechanism (IRM).		
10						
11	Q9.	Are you sp	ponsoring any e	exhibits in this proceeding?		
12	A9.	Yes. I am	Yes. I am sponsoring the following exhibits:			
13		<u>Exhibit</u>	<u>Schedule</u>	Description		
14		A-12	B5.4	Projected Capital Expenditures – Distribution Plant		
15				(Pages 1-7 & 12-21)		
16		A-12	B5.4.1	Pilots: NWA: O'Shea Energy Storage		
17		A-12	B5.4.2	Pilots: NWA: Battery Trailer		
18		A-12	B5.4.3	Pilots: NWA: Omega Load Relief		
19		A-12	B5.4.4	Pilots: NWA: Fisher Load Relief		
20		A-12	B5.4.5	Pilots: NWA: Port Austin Load Relief		
21		A-12	B5.4.6	Pilots: NWA: Veridian		
22		A-12	B5.4.7	Pilots: NWA: EV Charging Demonstration at ACM		
23		A-12	B5.4.9	NWA MPSC Case No. U-20836 Order Feedback		
24		A-23	M3	Distribution Plant Capital Project Detail –		
25				Base Capital		

Line				<b>B. L. HILL</b> U-21297		
<u>No.</u>		A 22				
1		A-23	Mo	Distribution Plant Capital Project Detail –		
2				Technology and Automation		
3				(excluding ADMS, ESOC/ASOC, and AMI projects)		
4		A-33	X2	Distribution – Base Investments +		
5				Infrastructure Recovery Mechanism		
6		A-33	X3	Distribution – Infrastructure Recovery Mechanism		
7						
8	Q10.	Were these e	exhibits prepar	red by you or under your direction?		
9	A10.	Yes, they we	re.			
10						
11	Q11.	How is your testimony organized?				
12	A11.	My testimony consists of the following four parts:				
13		Part I Infrastructure Recovery Mechanism (IRM) Support				
14		Part II Emergent Replacements				
15		Part III	Customer Connections, Relocations & Other			
16		Part IV	Technology and Automation Projects			
17						
18	<u>Part I</u>	: Infrastructu	ire Recovery N	Mechanism (IRM) Support		
19						
20	Q12.	Is the Comp	any proposing	that any of the capital programs discussed in your		
21		testimony a	nd exhibits	be associated with the Company's proposed		
22		Distribution	Infrastructure	e Recovery Mechanism (IRM)?		
23	A12.	. Yes. As part of the IRM proposal put forth by Company witness Foley, the				
24		Company is proposing that the 4.8kV Circuit Automation investment be authorized				
25		for IRM treat	ment.			

Line No.		<b>B. L. HILL</b> U-21297
1		
2	012	Why does the Company believe that it is appropriate for the 4 fly Circuit
Z	Q15.	why does the Company beneve that it is appropriate for the 4.8kv Circuit
3		Automation investment be authorized for IRM treatment?
4	A13.	The 4.8kv circuit automation investment is appropriate for the Distribution IRM
5		because it is a key safety and reliability program. The 4.8kV Circuit Automation
6		program will allow the Company to detect wire downs on 4.8kV circuits and
7		provide technology to remotely operate the circuits. Full benefits of the program
8		are discussed later in my testimony.
9		
10	Q14.	What level of investment is the Company proposing that the Commission
11		authorize under the Distribution IRM for this program?
12	A14.	As discussed by Company witness Foley, the Company is proposing a 37-month
13		IRM beginning concurrent with the projected test year in the instant case, 12
14		months ending November 30, 2024. The Company is proposing that IRM Plan Year
15		one (1) be 13 months such that subsequent IRM plan years are aligned to calendar
16		years. As captured in witness Foley's Exhibit A-33, Schedule X1, I am proposing
17		the following investment level shown in Table 1 for 4.8 kV Circuit Automation.
18		Table 1Distribution IRM Investments (\$millions)

	Projected Test Year	Plan Year 1	Plan Year 2	Plan Year 3
Capital Program	(12 mos. end 11/30/24)	13 mos. ending 12/31/2024	12 mos. ending 12/31/2025	12 mos. ending 12/31/2026
4.8 kV Circuit Automation	\$24	\$26	\$24	\$24

20As described by Company witness Foley, if the Company were to invest less than21these levels, the associated over-recovery of costs would be refunded to customers.

1		
2		The level of Distribution IRM Investments for the projected test year (12 months
3		ending 11/30/24) is supported on Exhibit A-33, Schedules X2 and X3, sponsored by
4		Company Witnesses Elliott Andahazy, Deol, and me. Schedule X2 distinguishes
5		expenditures included in the base rate request from the amounts included in the
6		proposed IRM request, while Schedule X3 details the IRM investments in detail by
7		project.
8		
9		For the 4.8kV Circuit Automation program, I am sponsoring an investment level of
10		\$24.4 million for 12 months ending 11/30/2024 on Exhibit A-33, Schedule X3, Line
11		35. This amount is also shown on Exhibit A-33, Schedule X2, line 15, column (c),
12		as part of the IRM expenditures separate from other Technology and Automation
13		expenditures included in the base rate request on line 14, column (b).
14		
15	Q15.	What does the Company intend to accomplish with 4.8kV Circuit Automation
16		program during the IRM timeframe?
17	A15.	The Company intends to install remote operated reclosers on prioritized 4.8kV
18		circuits by the end of 2027. Circuit prioritization is discussed later in my testimony.
19		
20	Q16.	How will the Company select specific projects to execute during the IRM
21		timeframe?
22	A16.	As discussed later in my testimony in Part IV, the Company has a prioritization
23		process for the 4.8kV system as to where the reclosers will be installed.
24		

## 1Q17. Is the Company proposing to begin reporting any program execution metrics2associated with the 4.8kV Circuit Automation program?

A 17. Yes. As part of the IRM Reconciliation Process described by Company witness
 Foley, the Company is proposing to begin reporting the metrics shown in Table 2.

5 6

#### Table 2IRM Program Execution Metrics

Program	Program Execution Metric*
4.8kV Circuit Automation	Units Installed
	Average cost per unit

\* measured vs. target

7

#### 8 Q18. What are the benefits of IRM treatment for the proposed capital programs?

- 9 A18. As further discussed by Company witness Foley, there are four key benefits of a
  10 Distribution IRM:
- Certainty of investment. The approval of an IRM effectively establishes a
   dedicated funding source for capital programs critical to customer safety,
   reliability, and/or resiliency. The Company would not be able to shift investment
   authorized for IRM treatment to programs outside the IRM, or between
   programs within it. Importantly, any underinvestment in the programs associated
   with IRM would be returned to customers.
- Greater transparency. As part of the Distribution IRM, new planning and
   reconciliation process would be established that would provide Staff with
   greater transparency into the Company's investment plans and its execution of
   those plans.

Line
<u>No.</u>

<u>lo.</u>		
1		- Opportunities for feedback. As part of the IRM Planning Process, Staff would
2		have the opportunity to review and provide feedback on the Company's planned
3		IRM investments for the upcoming year. Likewise, the Company would then
4		have the opportunity to address that feedback and respond to any questions or
5		concerns raised by Staff before execution of its plans.
6		- Increased accountability. As part of the IRM Reconciliation process, the
7		Company would begin reporting new program execution metrics to help assess
8		its execution of its investment plans.
9		
10	Parts	II & III: Base Capital Programs
11	Q19.	Can you please summarize what is included in Distribution Operations base
11 12	Q19.	Can you please summarize what is included in Distribution Operations base capital programs?
11 12 13	<b>Q19.</b> A19.	Can you please summarize what is included in Distribution Operations base capital programs? Capital investments in base capital programs summarized on Exhibit A-12,
11 12 13 14	<b>Q19.</b> A19.	Can you please summarize what is included in Distribution Operations base capital programs? Capital investments in base capital programs summarized on Exhibit A-12, Schedule B5.4, pages 1 and 2, include Emergent Replacements on lines 2 through
11 12 13 14 15	<b>Q19.</b> A19.	Can you please summarize what is included in Distribution Operations base capital programs? Capital investments in base capital programs summarized on Exhibit A-12, Schedule B5.4, pages 1 and 2, include Emergent Replacements on lines 2 through 7 and Customer Connections, Relocations & Other, on lines 8 through 16 (with
<ol> <li>11</li> <li>12</li> <li>13</li> <li>14</li> <li>15</li> <li>16</li> </ol>	<b>Q19.</b> A19.	Can you please summarize what is included in Distribution Operations base capital programs? Capital investments in base capital programs summarized on Exhibit A-12, Schedule B5.4, pages 1 and 2, include Emergent Replacements on lines 2 through 7 and Customer Connections, Relocations & Other, on lines 8 through 16 (with additional details on page 3 for Emergent Replacements and pages 4 through 7 for
<ol> <li>11</li> <li>12</li> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> </ol>	<b>Q19.</b> A19.	Can you please summarize what is included in Distribution Operations base capital programs? Capital investments in base capital programs summarized on Exhibit A-12, Schedule B5.4, pages 1 and 2, include Emergent Replacements on lines 2 through 7 and Customer Connections, Relocations & Other, on lines 8 through 16 (with additional details on page 3 for Emergent Replacements and pages 4 through 7 for Connections, Relocations & Other). Also included on Exhibit A-12, Schedule B5.4
<ol> <li>11</li> <li>12</li> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> </ol>	<b>Q19.</b> A19.	Can you please summarize what is included in Distribution Operations base capital programs? Capital investments in base capital programs summarized on Exhibit A-12, Schedule B5.4, pages 1 and 2, include Emergent Replacements on lines 2 through 7 and Customer Connections, Relocations & Other, on lines 8 through 16 (with additional details on page 3 for Emergent Replacements and pages 4 through 7 for Connections, Relocations & Other). Also included on Exhibit A-12, Schedule B5.4
<ol> <li>11</li> <li>12</li> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> </ol>	<b>Q19.</b> A19.	Can you please summarize what is included in Distribution Operations base capital programs? Capital investments in base capital programs summarized on Exhibit A-12, Schedule B5.4, pages 1 and 2, include Emergent Replacements on lines 2 through 7 and Customer Connections, Relocations & Other, on lines 8 through 16 (with additional details on page 3 for Emergent Replacements and pages 4 through 7 for Connections, Relocations & Other). Also included on Exhibit A-12, Schedule B5.4 for base capital programs is AFUDC on page 13 and plant activity on page 14, described in more detail by Company Witness Miller. Base capital programs are
<ol> <li>11</li> <li>12</li> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> </ol>	<b>Q19.</b> A19.	Can you please summarize what is included in Distribution Operations base capital programs? Capital investments in base capital programs summarized on Exhibit A-12, Schedule B5.4, pages 1 and 2, include Emergent Replacements on lines 2 through 7 and Customer Connections, Relocations & Other, on lines 8 through 16 (with additional details on page 3 for Emergent Replacements and pages 4 through 7 for Connections, Relocations & Other). Also included on Exhibit A-12, Schedule B5.4 for base capital programs is AFUDC on page 13 and plant activity on page 14, described in more detail by Company Witness Miller. Base capital programs are further supported on Exhibit A-23, Schedule M3.

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### **Part II: Emergent Replacements Emergent Replacements – Storm O20.** Generally, what is included in Emergent Replacement – Storm? A20. This category includes investments required to restore the overhead and underground distribution systems, the sub transmission system, and substations from damage which occurs during storms. A storm is defined as greater than 340 customer outage events (an outage event is when customers are left without power) impacting greater than 125 circuits. This typically is equivalent to 25,000 customers without power. These investments are necessary and prudent to replace damaged equipment that caused customer power outages and/or public hazards. Equipment examples include poles, crossarms, and conductors. This equipment is most often damaged by weather during storm conditions. An example of storm damage is when wind causes trees or tree branches to break, and they bring down poles and power lines. When poles and power lines break, they can result in customer power outages and create potential public safety hazards. **Q21.** A21.

17

#### 18 What is the Storm investment forecast for 2022 through 2024?

19 At the time the 2022 Storm expenditures used for the instant case were determined, 20 prior to the end of 2022, the Company forecasted expenditures to be \$177 million, 21 Exhibit A-12 Schedule B5.4, page 2, line 3, column (e). This forecast is lower than 22 the 5-year historic inflation adjusted average of \$206 million for the time-period 23 2017 through 2021, Exhibit A-12 Schedule B5.4, page 3, line 5, column (g). The 24 2022 storm expenditures are below the 5-year average because a) the number of 25 storm days were lower than the Company's internal forecast and b) there has been

1 only one catastrophic storm which is lower than the Company's internal forecast. 2 Storm expenditures for 2023 and 2024 are forecasted at \$221 million and \$227 3 million, Exhibit A-12 Schedule B5.4, page 2, line 3, columns (f) and (g), 4 respectively, based on a 5-year inflation adjusted historic average of the period 5 2017-2021. 6 7 Q22. Why is the Company forecasting 2023 and 2024 Storm expenditures using a 5-8 year inflation adjusted historic average when the 2022 forecast for Storm 9 expenditures is less than the 5-year average? 10 A22. The Company is using a 5-year inflation adjusted historic average to forecast 2023 11 and 2024 because this method is consistent with Commission orders in previous 12 Cases Nos. U-20162, U-20561, and Case No. U-20836. As noted by Staff witness

- 13 Becker: "[t]he Commission has consistently adopted a five-year average for 14 projected spend in the emergent replacements program in the past." Case No. U-15 20836 8T 5400. The Company used the five-year period of 2017-2021 because it 16 represented full, 12-month historical data for each of the 5-years. The 2022 storm 17 expenditure forecast includes actuals through November 2022 and estimated 18 expenditures for December 2022. Because the expense increase for labor and 19 materials for emergent investments are the same as in other investment categories, 20 the Company believes it is reasonable and prudent to apply inflation adjustments to 21 the historic expenses in this category as well.
- 22

#### 1 Summer of 2021 Storms

- Q23. Can you describe the number and nature of the storms that impacted the
  Company's service territory in the summer of 2021?
- A23. In three-months' time (June 20, 2021 September 29, 2021), the Company
  experienced 12 storm events that, when combined, were unprecedented in the
  Company's history in terms of frequency, intensity, and resulted in a frustrating
  summer of outages for our customers
- 8

9 These 12 storms included four Catastrophic (CAT-1 storms) and one Catastrophic 10 (CAT-2 storm) that caused more than twice as many customer outages than the same 11 period in any of the last five years. A CAT-1 storm is defined as 110,000 customers 12 or more without power in a 24-hour period (5% of customers affected). A CAT-2 13 storm is defined as 220,000 customers or more without power in a 24-hour period 14 (10% of customers affected). During this time, the extreme weather rolled in waves 15 with an average of only 4.6 days between storms, which is 30% fewer days between 16 storms compared to the same time over the last five year (2016-2021). Due to the 17 intensity and the frequency/short duration between storms, all storm damage could 18 not be fully repaired before the next weather event hit our service territory. This left 19 the electrical system in an abnormal condition with many temporary repairs 20 resulting in a frustrating summer of outages for our customers. The largest of these storms occurred on August 9<sup>th</sup>, 2021 and left more than 500,000 of the Company's 21 22 customers without power.

23

#### 1 Q24. Can you provide more detail on the August 9th, 2021 CAT-2 storm?

2 A24. On August 9, 2021, a severe weather system raced through Michigan leaving 3 approximately one million customers without power, some for extended periods of 4 time. This storm caused power outages for roughly 500,000 of the Company's 5 customers. The storm produced wind gusts in excess of 70 miles per hours (mph) 6 and the damage to trees and poles as a result of those gusts caused more than 11,000 7 reports of downed wires across the state. The August 9th storm was the fourth 8 catastrophic storm the Company experienced in just a six-week time period. Though referred to as the "August 9<sup>th</sup> storm", August 9<sup>th</sup> was the day the storm 9 10 began. Impacts from this extreme weather pattern continued to batter our electrical system over the next several days through August 12<sup>th</sup>. Wind gusts reached in 11 12 excess of 40 mph on three of those four days. Those periods of peak winds 13 coincided with lighting, which for safety reasons, requires overhead line crews and 14 damage assessment teams to suspend restoration efforts. On Wednesday August 11<sup>th</sup>, another organized line of severe and extreme storms moved across the state 15 16 causing widespread damage with recorded wind gusts of 75 miles per hour, which 17 aligns with the wind speed of a Category 1 hurricane. This four-day weather event 18 also brought periods of heavy rains, which not only impeded restoration efforts, but 19 the resultant flooding prevented crews and damage assessment teams from reaching 20 some areas where repairs were needed. Though the storm pattern lasted four days, 21 the restoration efforts continued through August 19<sup>th</sup>.

22

# Q25. What actions did the Company take to make the distribution system more resilient against high winds and storms like those experienced in the summer of 2021?

4 A25. Immediately following the 2021 storms, the Company identified communities that 5 had suffered the most impacts during this period. The Company implemented a 6 pre-storm season strengthening process that identified 527 circuits requiring 7 different scopes of work to improve reliability. The work included maintenance 8 tree trimming (trimming trees along the entire line of the circuit), spot tree trimming 9 (targeting tree trimming in areas where trees are most impacting the power lines), 10 customer excellence, pole and pole top maintenance & modernization (PTMM), 11 4.8kV Hardening, and other reliability work. The work on these circuits were 12 completed prior to the 2022 storm season to mitigate risk and customer outages that 13 resulted from the extreme 2021 storms. Investments made in tree trim are charged 14 to the standard O&M tree trim budget; investments made under PTMM, 4.8kV 15 Hardening, and Customer Excellence are charged to those respective projects. 16 Investments in other reliability work were initially charged to the System 17 Improvement budget, described later in my testimony. In 2023 and beyond, these 18 investments will be made under the Frequent Outage Program (CEMI). Both the 19 investments and customer benefits are supported by Company witness Elliott 20 Andahazy. These investments are reasonable and prudent to improve grid 21 resiliency, minimize customer outages and public safety hazards that are created by 22 the impact of increasing severe weather. The Company also committed an 23 additional \$90 million dollars to surge tree trim work, above the amount included 24 in rates for surge tree trim work. The Company will not seek to recover the tree 25 trim expenses from customers

#### 2 <u>Emergent Replacement – Non-Storm</u>

#### 3 Q26. Generally, what is included in Emergent Replacement – Non-Storm?

4 A26. This category includes capital replacements required to return the overhead and 5 underground distribution systems, and subtransmission electrical system to restore 6 power and/or return to normal operating configuration during non-storm 7 conditions. Non-storm conditions are defined as less than 340 customer outage 8 events (approximately 25,000 customers) for the entire system. It includes overhead 9 & underground distribution and the subtransmission system during non-storm 10 conditions but does not include planned strategic replacements. The "non-storm" 11 description does not imply that these events are not caused by storms, high winds, 12 or other weather-related events. It simply means that there were not enough 13 customer outages for the "storm" threshold to be declared. Severe weather damage 14 degrades the electrical system and subsequently results in emergent failures that 15 would then be considered non-storm emergent. Not all equipment failures lead to 16 outages. However, failed and damaged equipment is considered emergent and the 17 need to address is reasonable and prudent because it poses risk of power outages 18 and hazards. Examples of this type of work include the replacement of a failed 19 system cable or a broken insulator that has caused a floating line which could break 20 and create an outage or wire down. In addition to trees, some of the non-storm 21 causes for equipment failure include age, overloading, electrical or mechanical 22 issues, vehicles striking poles, or animal interference. Table 2 provides the high-23 level non-storm categories, brief descriptions, and examples.

24

#### Table 2 Emergent – Non-Storm Description

Category	Description	Example
Non-Storm Emergent	Emergency replacements of equipment during period outside of a declared storm, when customers experience issues with their power supply under both outage and non-outage conditions, but when the number of outages is below the Storm threshold	<ul> <li>7/7/2022, Dearborn Heights <ul> <li>Garbage truck hopper</li> <li>contacted a communications line</li> <li>and ripped down 5 spans of</li> <li>primary wire and also broke 4</li> <li>poles and 2 cross arms</li> <li>Crew cleared the hazards,</li> <li>restored most customers, replaced</li> <li>wires, replaced poles and then</li> <li>restored remaining customers</li> </ul> </li> </ul>
Non-Storm Reactive	Replacements of equipment that does not need immediate actions and can be scheduled to complete later. This includes replacements of failed devices that can be safely scheduled for later completion and follow-up work that is required to finalize the replacements of the assets after the initial work is complete to restore customer power or address immediate concerns	<ul> <li>4/13/2022, Detroit</li> <li>Report of a broken pole as the result of a vehicle accident; crew temporarily fixed pole so no hazards remained for later replacement</li> <li>Pole was replaced on 5/14/2022; this work was classified as "Non-Storm Reactive"</li> </ul>
Non-Storm Corrective	Replacements of equipment that are required to restore the system back to its normal condition and involve coordination from the System Operations Center (SOC)	<ul> <li>1/23/2022, Southfield</li> <li>Failed underground cable caused outage and underground crew restored customers, leaving system in abnormal condition</li> <li>Planned outage took place under direction of SOC on 1/27/2022 &amp; 1/28/2022 to replace damaged cable; this work was categorized as "Non-Storm Corrective"</li> </ul>
Non-Storm Environmental	The disposal of environmentally hazardous materials from the Company's retirement units/assets that are replaced in a period outside of a declared Storm	<ul> <li>3/13/2022, Detroit <ul> <li>Car hit pad mounted</li> <li>transformer, damaging transformer</li> <li>and causing oil leak</li> <li>Crew removed and contained</li> <li>transformer and replaced with</li> <li>new one</li> <li>Environmental crew cleaned up</li> <li>oil</li> </ul> </li> </ul>

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#### 3 Q27. What is the Non-Storm forecast for 2022 through 2024?

4 A27. At the time the 2022 non-storm expenditures were estimated for use in the instant

case, prior to the end of 2022, the Company forecasted expenditures to be \$265

1		million, Exhibit A-12 Schedule B5.4, page 2, line 4, column (e). This forecast is
2		higher than the 5-year historic inflation adjusted average of \$171 million for the
3		time-period 2017 through 2021, Exhibit A-12 Schedule B5.4, page 3, line 12,
4		column g. The 2022 non-storm expenditures are higher than the 5-year average and
5		is discussed later in my testimony. Non-storm expenditures for 2023 and 2024 are
6		forecasted at \$183 million and \$188 million, Exhibit A-12 Schedule B5.4, page 2,
7		line 4, columns f and g, respectively, based on a 5-year inflation adjusted historic
8		average of the period 2017-2021.
9		
10	Q28.	Why is the Company forecasting 2023 and 2024 Non-Storm expenditures using
11		a 5-year inflation adjusted historic average when the 2022 forecast for Non-
12		Storm expenditures is greater than the 5-year average?
13	A28.	The Company is using a 5-year inflation adjusted historic average to forecast 2023
14		and 2024 because this method is consistent with the Commission's order in
15		previous Cases Nos. U-20162, U-20561, U-20836. As noted by Staff witness
16		Becker: "[t]he Commission has consistently adopted a five-year average for
17		projected spend in the emergent replacements program in the past." Case No. U-
18		20836 8T 5400. The 2022 non-storm expenditure forecast includes actuals through
19		November 2022 and estimated expenditures for December 2022. Because the
20		expense increase for labor and materials for emergent investments are the same as
21		in other investment categories, the Company believes it is reasonable and prudent
22		to apply inflation adjustments to the historic expenses in this category as well.
23		
24		
25		

#### Q29. Why has Emergent Replacement – Non-Storm been higher than current 1 2 forecast? 3 A29. There are several drivers that contributed to the higher than forecast non-storm 4 capital expenditures: 5 (1) Global supply chain issues and raw material shortages have resulted in higher 6 material costs for equipment. For example, the costs of poles have increased by 7 20% and transformers by 30%. In addition, material usage was higher than the 8 forecast resulting from an increase in event volume. 9 10 The grid is facing reliability and resiliency challenges posed by aging (2)11 infrastructure and stronger, more frequent storms. In response the Company has 12 greater emphasis on replacing aged and outdated equipment with new equipment 13 that has a higher technical standard rather than merely repairing the failed 14 equipment. The increasing number of outages, paired with the age of the equipment, 15 have led the Company to conclude that in most cases older infrastructure should be 16 replaced when it fails to avoid repeat occurrences. For example, a span of wire that 17 has previously been repaired with multiple sleeves will typically be replaced when 18 it fails again, as opposed to adding an additional sleeve. This change is in the best 19 interest of customers, as it improves system resiliency and avoids the need to incur 20 cost to repair the same asset on a repeat basis. 21 22 (3) Another driver to improve reliability and resiliency that benefit our customers

was the shift to higher specification materials. For example, the use of fiberglass
 crossarms, which provide much greater longevity and resistance to damage, though
 initially they cost more than traditional wood crossarms. The Company has also

> 1 upgraded wood pole construction standards, including increasing the minimum 2 pole class and installing taller poles that allow for the more tree-resistant armless 3 construction. The change in pole specifications has increased the strength of poles 4 by a factor of more than 2.5. For example, if a large tree limb falls across aged 5 and degraded infrastructure it generally will break wires, cross arms, or poles 6 leading to extensive damage resulting in longer restoration times. By upgrading 7 and replacing old equipment with higher specification materials, a tree limb falling 8 onto the wires would only require the branch to be removed from the wire and 9 power can be immediately restored. This is because higher specification materials 10 provide greater resistance to damage and are less likely to break. Implementation 11 of these higher standards is reasonable and increases resiliency, reliability, and 12 safety for customers and employees in the field.

13

14 (4) The Company has experienced approximately a 6% increase in non-storm 15 emergent events vs. the historical average, 2018-2020 that produced the forecast in 16 Case No. U-20836. Non-storm events happen outside a defined storm and cause 17 customers to lose power, present a hazard, or prevent the system from operating as 18 designed. As mentioned earlier in my testimony, the "non-storm" description does 19 not imply that these events are not caused by storms, high winds, or other weather-20 related events. It simply means that there were not enough customer outages for 21 the "storm" threshold to be declared. Stronger, more frequent storms impact aging 22 infrastructure and subsequently results in emergent failures that would then be 23 considered non-storm emergent.

24

B.	L.	HILL
	U-	21297

Line <u>No.</u>	U-21297
1	(5) In addition to an increase in the overall number of non-storm emergent events,
2	there was also a jump in significant events. Significant events include actual
3	customer outages or risk of extended customer outages. Significant events are
4	defined as follows:
5	A). Customers Outages
6 7	<ul> <li>&gt;200 customer outages with a restoration plan which will exceed 8 hours to implement</li> </ul>
8	• Any single substation that is completely de-energized
9	$\sim > 5000$ customer outages in a single event regardless of contingency
10	nlan or customer restoration time
10	plan of eastonier restoration time
12	B). Risk of Extended Customer Outages
13	• Work orders with contingency plans that will exceed 8 hours to
14	implement and equipment repair schedules that will take longer than
15	1 week to implement
16	• Loss of major equipment or telecommunications systems with
17	system reliability concerns, or critical customer impact
18	• Any event that may result in significant reputational risk (such as
19	circuit with several primary or critical customers, substation fire,
20	etc)
21	
22	Due to actual or potential risk of customer outages, significant events are worked

ents are worked 23 24-hours around the clock and in some cases the Company implements its Incident 24 Command Structure (ICS) to lead and address the issue. Significant events are more costly and often require the deployment of portable generation to restore power. 25 26 An example of a significant event occurred on July 19, 2022. Two underground cable lines failed while in service within a 4-hour period resulting in approximately 27 11,000 customers without power in east Detroit. The first failure resulted in the loss 28 29 of ~3,000 customers and the following failure resulted in the loss of an additional 30 ~8,000 customers. The failures occurred in July when the system experienced peak 31 loading, making it impossible to shift this customer load to other cables. The 32 Company activated its Incident Command team and worked around the clock to

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restore power to our customers and replace the failed cables. This event also included the use of portable generation which increased cost but provided the ability to restore customers as the longer-term underground cable replacement work was completed. Addressing non-storm emergent events (including significant events) is reasonable and is in the best interest of customers as it restores power and/or immediately addresses system issues that pose risk of customer outages.

7

8 (6) Storm preparation and resource ramp up impacted non-storm emergent spend. 9 The Company monitors risk of severe and extreme weather as part of its emergency planning and preparation process. A DTE meteorologist monitors weather 10 11 conditions including forecasts from the National Weather Service. This ensures the 12 Company is prepared and ready to immediately respond to public safety hazards 13 and customer outages when weather impacts the electric system. In March 2022, 14 an extreme weather pattern developed resulting in a forecast of damaging rain and 15 high winds impacting our service territory. Based upon this forecast and the 16 possibility of large and widespread damage, the company ramped up resources and 17 brought in additional out of state crews in advance of the pending weather. In its 18 August 25, 2021, Order in Case No. U-21122 at page three the MPSC stated: "The 19 Commission's focus is on the issues of reliability, resilience, and readiness for these 20 extreme events. Ratepayers have a right to expect the utilities to anticipate extreme 21 weather events, to provide a hardened grid that can withstand extreme weather, and 22 to be prepared to restore power expediently when the grid fails; and the Commission 23 is committed to implementing improvements in these areas." Ramping additional 24 storm crews takes 36-48 hours before crews arrive on property and are available to 25 work in the field. Advanced securement and mobilization of the crews ensured that

1 the company had additional storm labor resources and they were on property ready 2 to work before the weather arrived so that it could immediately address the potential 3 large impact from this extreme weather event. The extreme weather missed our 4 service area. The weather pattern did cause customer outages however the number 5 of customers impacted did not reach storm threshold as defined earlier in my 6 testimony. However, the storm labor resources that were brought in on property 7 were utilized and put to work. They immediately were assigned jobs to restore 8 customers without power and address public hazards. Since storm was not 9 declared, their costs for performing this work were charged to non-storm emergent. 10 Securing and early retention of additional storm resources in advance of extreme 11 weather is consistent with the guidance provided by the MPSC in its Order in Case 12 No. U-21122. This advanced action ensures that the Company is prepared and able 13 to restore power expediently and respond to public safety hazards such as wire 14 downs.

15

Line

No.

16 (7) Increased use of higher cost contractor labor. As a result of the extreme 2021 17 storms and a frustrating summer of outages for our customers, the Company 18 increased the use of contractor labor on non-storm trouble follow-up events. In the 19 past, non-storm trouble follow-up events that did not pose an immediate hazard 20 were worked as crews had available capacity. The Company made this decision 21 because of the unprecedented customer impacts from the 2021 storms and to 22 mitigate risk of potential future outages. For example, wind damages a pole 23 resulting in customers without power. A crew is dispatched to the outage event and 24 upon arrival determines it can quickly restore customers by stabilizing the pole and 25 temporarily deferring replacement. The crew will restore power and write a follow
1		up work order to replace the pole. This benefits the customer because it results in
2		faster power restoration. Deferring the pole replacement (which requires a large
3		amount of labor, equipment, miss dig staking, and time) to the future by creating a
4		follow up work order allow linemen to quickly restore power and then move onto
5		other customer outages or public safety hazards. To help mitigate outage risk and
6		avoid further customer frustrations from the 2021 storms, this work was prioritized
7		and the additional work demand required the use of more expensive contractor
8		labor.
9		
10	Q30.	Does the Company have enough linemen to execute and construct all work
11		types now?
12	A30.	Yes. The Company has been able to obtain the necessary number of linemen
13		required to execute and construct all work. This includes emergent, customer
14		connections/relocations, and the increase in strategic work. The Company has hired
15		internal lineman and apprentices. In addition, it has more than doubled the number
16		of contractor linemen working in our service territory over the past several years.
17		
18	Q31.	Does the Company forecast the need to hire additional linemen?
19	A31.	Yes. The Company is forecasting the need to hire additional linemen over the next
20		several years to execute and construct all work. This includes emergent, customer
21		connections/relocations, and the increase in strategic work. The Company will
22		continue to internally hire lineman and apprentices. It will also increase the use of
23		contractor linemen and apprentices. Managing and monitoring the journeymen to
24		apprentice ratios both internally and externally with our contractors is necessary

Line <u>No.</u>		<b>B. L. HILL</b> U-21297
1		because it takes approximately 4-years for an apprentice to become a fully qualified
2		journeyman lineman. This is discussed later in my testimony.
3		
4	Q32.	Why is the Company using out of state contractor linemen?
5	A32.	Higher work demand required the need for additional contractor linemen. The
6		Company is using out of state linemen because there is currently not enough local
7		contractor linemen available.
8		
9	Q33.	What are the impacts of using out of state linemen?
10	A33.	Out of state linemen have higher costs for expenses including travel, hotels, and
11		meals. In addition, to obtain out of state linemen to work on DTE property, the
12		labor market requires 60-hour work-week schedules resulting in overtime rates.
13		Out of state linemen typically work as 3 or 4 man-crews as they travel together on
14		trucks, and remain together as a crew while working. These crews also have local
15		apprentices (it takes approximately 4-years for an apprentice to become a fully
16		qualified journeyman lineman) that are limited in the type of work that they are
17		allowed to perform, resulting in some loss of efficiency. However, adding
18		apprentices to work with out of state crews is essential for ensuring that there are
19		enough local linemen available to support building the grid of the future and replace
20		the large number of retirements forecasted as a result of attrition.
21		
22	Q34.	Why is the company using and increasing the number of linemen apprentices?
23	A34.	The company is forecasting the need to increase the number of journeymen linemen

by approximately 22% over the next 5-years as mentioned earlier in my testimonyand there are currently not enough local resources available to meet this demand.

1	Increasing and maximizing the journeyman/apprentice crew ratios now is critical
2	to grow and create a local workforce as it takes approximately 4-years for an
3	apprentice to become a fully qualified journeyman lineman. There is a national
4	shortage of journeymen linemen and utilities are competing for this labor resource.
5	Maximizing the apprentice program is reasonable and prudent to ensure there are
6	enough journeymen linemen available now and, in the future, to address customer
7	outages, public hazards, connect customers to the grid, and construct the grid of the
8	future.
9	

10 Q35. Would it be reasonable or prudent to defer Emergent Replacement – Storm &
 11 Non-Storm?

12 A35. No. This work is reasonable and prudent because there are system hazards, 13 customers without power or partial power. Deferring this work would leave 14 customers without power, reduce grid resiliency, poses system risk of additional 15 equipment damage resulting in further customer outages, and leave critical 16 equipment in abnormal conditions. A learning from the 2021 storms was that faster 17 response to address abnormal circuits and equipment as much as reasonably 18 possible before the next weather pattern impacts our service territory mitigates risk 19 for larger customer outages.

20

#### 21 Emergent Replacement - Substation Reactive

#### 22 Q36. Generally, what does Emergent Replacement – Substation Reactive include?

A36. This category includes investments required to perform emergency replacements
 for substation equipment. The Company makes these investments to replace broken
 equipment that either led to customer outages, created risk of customer outages, or

Line <u>No.</u>	<b>B. L. HILL</b> U-21297
1	impacted the operability of the electrical system. Table 3 provides the high-level
2	substation reactive categories, a brief description, and an example.

Table 3	Emergent – Substation Reactive Description
I abic 5	Emergent – Substation Reactive Description

Category	Description	Example
Substation Reactive - Major Equipment	Replacement of the Company's substation equipment classified as major equipment	<ul> <li>August 2022 Twelve Mile</li> <li>A fire led to the catastrophic failure and complete loss of the substation</li> <li>To restore the customers the Company deployed portable equipment including a substation, and multiple generators</li> </ul>
Substation Reactive -Minor Equipment	Replacement of substation equipment classified as minor equipment	<ul><li>April 2022 UNVIL</li><li>40kV insulator broked free</li><li>Replaced 3 40kV insulators</li></ul>
Substation Reactive -Transformers & Regulators	Replacement of substation transformers and regulators	October 2022 Middlebelt Transformer 2 • 40 year old transformer failed internally causing customers to lose power • Load was swithced to an another transformer for 2 days until the change out of Transformer 2 was complete
Substation Reactive - Non-Electrical Equipment	Replacement of substation retirement units/assets not directly related to the generation or transmission of electricity	Control House HVAC heating to remove condensation to mitigate equipment corrosion Fence/gate repairs which are mandated by NERC security protocol

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#### 5 Q37. What is the Substation Reactive investment forecast for 2022 through 2024?

6	A37.	At the time the 2022 Storm expenditures used for the instant case were determined,
7		prior to the end of 2022, the Company forecasted expenditures to be \$45 million,
8		Exhibit A-12 Schedule B5.4, page 2, line 5, column (e). This forecast is consistent
9		with the 5-year historic inflation adjusted average of \$43 million for the time-period
10		2017 through 2021, Exhibit A-12 Schedule B5.4, page 3, line 19, column (g).
11		Substation Reactive expenditures for 2023 and 2024 are forecasted at \$46 million
12		and \$47 million, Exhibit A-12 Schedule B5.4, page 2, line 5, columns (f) and (g),
13		respectively, based on a 5-year inflation adjusted historic average of the period
14		2017-2021.

# Q38. Can you discuss the emergent substation expenditures associated with the failure at the Twelve Mile substation in 2022?

4 A38. In August of 2022, a transformer secondary breaker catastrophically failed that 5 caused a fire in the outdoor breaker cubicle. The fire, and the water used by the fire 6 department, caused extensive damage at the Twelve Mile substation. The loss of 7 the outdoor breaker cubicle resulted in approximately 7,700 customers without 8 power. To restore power to the impacted customers, the Company activated its 9 Incident Command Structure (ICS) to address this event. The ICS team jumpered 10 load to adjacent circuits where possible, deployed mobile assets (diesel generators 11 and a portable substation), and replaced critical breakers to restore power to the 12 impacted customers. The use of this type of portable equipment is only a temporary 13 solution and replacement of the damaged equipment was necessary to restore the 14 station back to its designed configuration. The Company is well prepared to handle 15 these types of situations; however, the Company does not know ahead of time 16 where or when this type of failure will occur, making these expenditures purely reactive in nature. 17

18

#### 19 Q39. Is work still being performed at Twelve Mile substation?

A39. Yes. After replacing damaged equipment and restoring customers, it was
determined that the remaining undamaged oil breakers at Twelve Mile needed to
be replaced to prevent a future occurrence. The two remaining oil breakers are
planned to be replaced in 2023 and the work will be performed under the
Company's strategic Breaker Replacement Program, Exhibit A-12 Schedule B5.4
page 8, line 16.

Line No.

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3

040 Why are

# Q40. Why are non-electrical substation equipment failures classified under substation reactive expenditures?

4 A40. They are classified this way because these pieces of equipment are critical for 5 safety, reliability, and security of the distribution grid. For example, sub-station 6 fencing prevents the public from entering energized high voltage areas, protects 7 critical equipment, and is part of the grid security plan. When fencing and other 8 physical security type devices fail in an emergent manner, they need to be replaced 9 quickly to ensure public safety and protect the security of the gird. Other equipment 10 like HVAC systems control temperature and condensation in the substation. If this 11 equipment fails, it must be immediately replaced to ensure that the substation 12 operates as designed. These activities are truly reactive in nature and require the 13 Company to take immediate, prudent action to protect the safety, reliability, and 14 security of the electrical system.

15

# 16 Q41. Would it be reasonable or prudent to defer Emergent Replacement – 17 Substation Reactive?

A41. No. This work is to replace critical electrical grid equipment that has failed. When
substation equipment fails, it can in some cases leave thousands of customers
without power for extended periods of time. The failed equipment significantly
reduces distribution capacity and redundancy that is necessary to serve customers
in the event of additional system failures and increased seasonal loads. Both these
conditions increase risk of additional customer outages. Substation capacity and
redundancy is critical and required because these types of failures generally result

Line No.		<b>B. L. HILL</b> U-21297
1		in repairs that are very lengthy in time (weeks or months) which could result in
2		extended customer outages.
3		
4	Q42.	Can you provide additional details regarding Emergent Capital categories for
5		all storm, non-storm, and substation reactive expenditures?
6	A42.	Yes. The Order in Case No. U-20561, page 86 the Company was directed that "in
7		its next electric rate case filing, to provide a detailed description of each type of
8		expenditures assigned to the emergent replacements category." The Company
9		provided that information in Case No. U-20836 4T 253-257. Categories of storm,
10		non-storm, and substation reactive, along with descriptions and examples, are
11		provided in my testimony in Tables 1-3. Expenditures in Storm and Non-Storm
12		Emergent are incurred in support of the field activities under eight work type
13		categories: Emergency Job Critical Infrastructure Customer, Hazards, Multiple
14		Customer Outage, Police/Fire, Public Safety Concern, Single Customer Outage,
15		and Single Customer Problem. Table 4 provides examples for each category.
16		
17		Table 4Storm and Non-Storm Work Category
18 19		

Line <u>No.</u>

Category	Description
Emergency Job	Non-outage events of the highest priority. These events are restricted to situations where the health and safety of a person are at imminent risk. These events are limited to a person contacting the Company's electrical equipment or being trapped in a vehicle, building or elevator due to a power failure, downed wire, broken pole, etc.
Critical	Outages affecting hospitals, schools, water and wastewater systems, or
Infrastructure	other critical infrastructure customers
Customer	
Hazards	Non-outage events reported by a customer to alert the Company of a potentially hazardous situation due to a sparking wire, broken pole, pole top fire, or a tree / tree branch resting on a wire.
Multiple Customer Outage	Outage events affecting more than one customer on a circuit. Events are created by the Outage Management System (OMS) prediction engine, which uses customers calls, AMI data, and the Company's network model to determine the size and extent of the outage. The extent of the outage events can be at a single transformer, fuse, sectionalizing/protection device, or entire circuit level. The outage events can be caused by weather, trees, animals, public interference (such as automobile accidents), and equipment failures, and they can involve concerted efforts from overhead, underground and substation resources to restore power to the end customers.
Police/Fire	Non-outage events reported by a police or fire department. These events are created when a police or fire department utilizes their unique pin number when utilizing one of the Company's trouble reporting channels

Line No.

Category	Description
	to notify the Company of a hazardous situation (e.g. downed power line, structure on fire due to the Company equipment) at which they are standing by.
Public Safety Concern	Non-outage events reported by a customer where a primary or secondary wire is believed to have fallen that may pose a safety concern to the public.
Single Customer Outage	Outage events affecting a single customer. These events utilize the same inputs as Multiple Customer Outages (customer calls & AMI outage notifications) but remain at a single customer level.
Single Customer Problem	Non-outage events affecting a single customer that is not an outage and can include power quality issues, such as low voltage and flickering lights, or downed service drops where the customer still has power.

1

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Q43. Has the Company studied the Commission's directive in Ordering paragraph
Y in Case No. U-20836 that "DTE Electric Company shall begin tracking
equipment identified as imminent failure (near failure but has not failed) and
exclude those costs from the emergent replacement's capital program?"

7 Yes. The Company reviewed this directive and is not able to strictly comply with A43. 8 the directive, in the storm and non-storm categories, because it is not able to track 9 in all circumstances and in all equipment classes those deemed to be at risk of 10 imminent failure separate from equipment that has already failed. For example, a 11 lineman is dispatched to a location in response to a floating wire (this is a hazard 12 because the wire is not secured on the cross arm). The lineman arrives and 13 immediately identifies a broken insulator that is not securing the wire to the cross 14 arm. As the lineman ascends the pole, they then identify that the cross arm is rotted. 15 At this time the lineman would make the decision to replace both the insulator (the 16 broken insulator created the floating wire) and rotted cross arm. In this example, 17 two pieces of defective equipment was replaced. However, it would be highly 18 inefficient and nearly impossible for the lineman to track these replacements and their associated work time separately. The decision to make replacements under 19

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emergent scopes of work is typically made when field personnel determine in the moment that equipment is at risk of imminent failure. This is not planned work as described by Company witness Miller. These types of imminent failure are different than potential failures that are identified through the Company's capital replacement programs such as Pole Replacements, Breaker Replacement and System Cable Replacement.

7

6

# Q44. Can the Company track equipment identified as imminent failure (near failure but has not failed) separate from failures in substation reactive emergent?

10 A44. Yes, in some cases. The Company performs predictive and preventive maintenance 11 on substation equipment such as transformers, 120kV disconnects, 24kV/40kV12 breakers, distribution breakers, and regulators. Currently expenditures associated 13 with replacing equipment that has failed the predictive or preventive maintenance 14 programs is categorized as substation reactive. The Company believes that it can 15 begin tracking these expenditures separately from the expenditures associated with 16 failed equipment and include this detail in the emergent category. The process of 17 identifying these expenditures and tracking them will begin in 2023. The Company 18 does however maintain that these expenditures are still emergent in nature as the 19 equipment was not scheduled to be replaced and is only being replaced due to risk 20 of failure.

21

1	Part ]	III Customer Connections, Relocations & Other Capital Investments
2		
3	Q45.	Can you please describe the Company's Customer Connections, Relocations
4		& Other Capital Investments?
5	A45.	The customer connections, relocations and other investments category is broken
6		down in to six major subcategories: (1) Customer Connections and New Load; (2)
7		Relocations; (3) Electric System Equipment; (4) Normal Retirement Unit Change-
8		out (NRUC) and Improvement Blankets; (5) General Plant, Tools & Equipment
9		and Miscellaneous; and (6) Public Lighting Department Project. These six
10		subcategories are discussed in more detail below.
11		
12	Q46.	What capital expenditures fall into the Customer Connections and New Load
13		subcategory?
14	A46.	Connections and New Load expenditures include: (1) Small Load Growth Projects
15		(2) Customer Connections, and (3) New Business Projects.
16		
17		Small Load Growth Projects and Customer Connections are similar. They are
18		projects required to serve new load, upgrades necessary to address loading issues,
19		and connect customers to the electrical system. Activities may include
20		reconductoring lines, expanding a substation, or transferring load to provide local
21		capacity. The Company could also install additional overhead and underground
22		lines to provide service to small commercial businesses or housing developments.
23		Small Load Growth & Customer Connections projects typically cost less than
24		\$500,000 to complete and are developed and executed by distribution regional
25		service centers. Small Load Growth & Customer Connections projects are often

l	requested by customers and can carry a customer contribution in aid of construction
2	(CIAC) cost wherein the customer pays an allocated cost of new service depending
3	on the load requested and service requirements.

5 New Business Projects are required to serve new load, connect customers to the 6 electrical system, or to address local loading issues, just on a larger scale. These 7 are larger customer-driven projects that typically cost more than \$500,000 and 8 requires an engineered design to connect customers to the electrical system. New 9 Business projects often are requested by customers and can also carry a CIAC cost wherein the customer may be responsible for an allocated cost of system upgrades, 10 11 depending on the existing system conditions, the load requested and the impact to 12 the electrical system.

13

## 14 Q47. What capital expenditures fall into the Relocation subcategory?

A47. Relocation projects are requests from customers, cities, municipalities, or other
governmental entities, for example, the Michigan Department of Transportation.
These are requests to relocate existing Company equipment and facilities. These
requests are typically related to construction activities in specific geographic areas,
including the modification of roadways, bridges, water mains, public sanitation,
alleys, or other customer activities.

21

The Company equipment being relocated could include overhead lines and poles, underground lines and transformers, and substations equipment. With expected federal investment in replacing and building infrastructure, it is forecasted that

Line <u>No.</u>		<b>B. L. HILL</b> U-21297
1		these types of projects will become more frequent. As federal funds become
2		available, the Company will seek to use those funds where possible.
3		
4		These investments enable economic growth, meet customer needs, required by
5		regulation, or at the request of governmental entities. Like Customer Connections
6		and New Business, some projects in this category can carry a CIAC cost to the
7		requester, wherein the requester pays for part of the costs of relocating Company
8		assets.
9		
10	Q48.	What capital expenditures fall into the Electric System Equipment
11		subcategory?
12	A48.	The Company maintains an inventory of critical spare equipment to support
13		emergent replacements and planned projects. Equipment purchased under this
14		subcategory includes substation transformers, distribution transformers, regulators,
15		and meters. This equipment often has long lead-times, which have been increasing
16		due to global supply chain and raw material issues. To ensure we can provide
17		electrical service when critical equipment fails or to connect new customers, the
18		Company plans and maintains necessary inventory levels of critical electrical
19		system equipment.
20		
21	Q49.	What capital expenditures fall into the NRUC and Improvement Blankets
22		subcategory?
23	A49.	The expenditures that fall into this subcategory include: (1) System Improvements,
24		(2) Normal Retirement Unit Change-Out (NRUC), (3) Operational Technologies,

25 (4) Batteries and Chargers, and (5) Animal Mitigation.

1	1.	System Improvement projects are focused on reducing the frequency and
2		duration of customer outages. They are small projects managed by regional
3		operations to immediately address customer issues and complaints. These
4		projects do not exceed \$350,000 and do not require extended planning and
5		design.
6	2.	Normal Retirement Unit Change-Out (NRUC) consists of projects to
7		perform scheduled work that replace assets determined to be at end-of-life.
8	3.	Operational Technologies consists of the infrastructure and associated
9		applications that support the AMI platform and data. This also covers
10		annual work in testing new meter types, designing and installing
11		configurations, replacing communications equipment, and testing changes
12		for new equipment.
13	4.	Batteries and Chargers and Animal Mitigation have been reviewed by the
14		Company, per Staff request in U-20836, and determined to be better
15		categorized as strategic projects. Batteries and Chargers Replacement
16		Program has been moved to the Infrastructure Resilience and Hardening
17		pillar as a standalone program. Animal Mitigation has been moved to the
18		Frequent Outage Programs (CEMI) line item. Both are supported by
19		Company witness Elliott Andahazy. This change will be tracked going
20		forward from 2023 and beyond. The investments for 2021 and 2022 are still
21		shown in NRUC and Improvement Blankets for comparison purposes.
22		

Line <u>No.</u>

1	Q50.	What investments drove the 2022 increase in System Improvements (Exhibit
2		A-12 Schedule B5.4 page 5, line 28 column (c)?
3	A50.	As stated earlier in my testimony (Q/A24), because of the extreme 2021 storms and
4		a frustrating summer of outages for our customers the Company identified
5		communities that had suffered the most impacts during this period. The Company
6		implemented a pre-storm season strengthening process that identified 527 circuits
7		requiring different scopes of work to improve reliability. Regional operations
8		planned and executed work on 82 circuits in 2022 as part of this process. This work
9		was performed under and charged to the current System Improvement budget and
10		not tracked as a new program or work scope. The Company is showing the 2022
11		pre-storm season strengthening investments in the System Improvement line item,
12		Exhibit A-12 Schedule B5.4, page 5 line 28. The System Improvement budget for
13		the calendar years 2023 and 2024 were set based on 2021 historic investment levels.
14		
15	Q51.	Will the Company continue to track the Pre-storm Season Strengthening
16		investments in the System Improvement Budget?
17	A51.	No. As the Company reviewed its categorizations it realized that the pre-storm
18		season strengthening investments are more strategic. In 2023 and beyond, the pre-
19		storm season strengthening investments will be tracked in the Frequent Outage
20		Program (CEMI) budget, Exhibit A-23 Schedule B5.4 page 8, line 15; supported
21		by Company witness Elliott Andahazy.
22		

- Q52. Has the Company studied the customer connections, relocations & other
   program and re-assigned programs that do not align with this categories
   purpose?
- 4 A52. Yes. As previously discussed in my testimony, the Company removed Animal
  5 Mitigation and Batteries and Charges from Customer Connections, Relocations &
  6 Other to strategic capital. The Company will continue to review its project
  7 categorization and adjust in the future to help ensure alignment of investment
  8 categories.
- 9

# Q53. What capital expenditures fall into the General Plant, Tools & Equipment, and Miscellaneous subcategory?

- A53. General Plant, Tools & Equipment, and Miscellaneous includes new tools as well
  as beyond useful life replacement tools required for field workers to perform their
  tasks. It also includes engineering test equipment and substation physical security.
  These expenditures ensure that Company workers have the necessary tools and
  equipment to conduct and construct field work. Examples of items include meters,
  phase sets, and infrared cameras. It also includes DC hi-potential testers (Hipoters)
  that are used to test insulation on cable, breakers, transformers, etc.
- 19

# 20 Q54. What is the Public Lighting Department Project?

A54. The Public Lighting Department (PLD) project includes the conversion of former
 PLD customers to the Company's distribution system. Working includes extending
 the Company's OH and underground system such as transformer replacement and
 line extensions. Remaining work under the PLD project includes removal of three

Line No.		<b>B. L. HILL</b> U-21297
1		breakers from Waterman substation and final connection of the Detroit Institute of
2		Art (DIA), as well as project close out.
3		
4	<u>Part l</u>	V Technology and Automation
5	Q55.	Can you please describe the Company's Technology and Automation capital
6		investments?
7	A55.	Investments in technology and automation are tightly linked to grid modernization.
8		The current grid has limited technology and automation and these limits will create
9		challenges as our customers increase their adoption of technologies, including
10		electric vehicles, distributed generation, and storage. These investments develop
11		capabilities in grid observability, analytics and computing, controls, and
12		communications of the electrical system. The Company's technology and
13		automation projects and programs presented in the instant case meet current grid
14		requirements and provide immediate customer benefits. For example, increased
15		automation of the Company's substations and circuits will reduce outage frequency
16		and duration, improve reliability, and safety, particularly when linked with the
17		capabilities of the new advanced distribution management system (ADMS).
18		Additionally, these investments lay the foundation for grid modernization and are
19		necessary to support increased adoption of distributed energy resources (DERs) and
20		electric vehicles (EVs). These investments are described in summary on Exhibit A-
21		12, Schedule B5.4, page 12 and in more detail in Exhibit A-23, Schedule M6
22		Distribution Plant Capital Project Detail - Technology and Automation. Also
23		included on Exhibit A-12, Schedule B5.4 for this category is AFUDC on page 13
24		and plant activity on pages 19 through 21, described in more detail by Company
25		Witness Miller.

Line		<b>B. L. HILL</b> U-21297
<u>No.</u>		
1		
2	Q56.	Are there specific Technology and Automation investments you would like to
3		discuss in more detail?
4	A56.	Yes. I would like to highlight the following because I believe that discussion
5		beyond what is contained in the exhibits will be helpful in establishing a deeper
6		understanding of their scope, rationale, necessity, and customer benefits from these
7		investments:
8		• 4.8kV Circuit Automation
9		Grid Automation Telecommunications
10		Distribution Automation
11		• Non-Wires Alternatives (NWA) Pilots
12		• CVR/VVO
13		
14	4	4.8kV Circuit Automation
15	Q57.	What is the 4.8kV Circuit Automation project?
16	A57.	The 4.8kV Circuit Automation project will install remote-operating reclosers at or
17		as close as possible to the beginning of 4.8kV circuits. The reclosers communicate
18		real-time information and will open and operate with a fault. The recloser will send
19		ground alarms to the system operation center (SOC) when a wire is down. When
20		system operations receive the alarm, the technology provides the ability to remotely
21		isolate the ground beyond the recloser and mobilize crews to repair resulting in
22		faster wire down and customer outage response times.
23		

Q58.	Why is it important for the SOC to have the ability to remotely isolate the
	ground on the 4.8kV system?
A58.	Installing remote-operating reclosers will address safety and reliability issues
	associated with the 4.8kV system. Page 313 of Exhibit A-23 Schedule M7 DGP,
	sponsored by Company witness Robinson, discusses the design and some of the
	challenges of the 4.8kV system. The ability for the SOC to remotely isolate the
	ground beyond the recloser allows the Company to mobilize crews faster to downed
	wires and reduces customer outage times.
Q59.	What are the prioritization criteria for the 4.8kV Circuit Automation project?
A59.	Prioritization was performed at the substation level, much like the 4.8kV Hardening
	program, as it is more efficient to plan and perform the work for a group of circuits
	tied to the same substation. Safety related factors were used to prioritize the
	substation areas. Each substation was scored and ranked based on the following
	factors:
	1) Recorded wire downs per overhead line mile; and
	2) Estimated foot traffic within the substation service area.
	Substations with existing supervisory control and data acquisition (SCADA)
	technology and those scheduled for decommissioning as part of the conversion plan
	were excluded from the ranking.
Q60.	What is the Company's forecast and plan for the 4.8kV Circuit Automation?
A60.	Under the 4.8kV Circuit Automation plan the Company is forecasting and intends
	to install remote-operating reclosers on all the 4.8kV circuits; except for circuits
	<b>Q58.</b> A58. <b>Q59.</b> A59. <b>Q60.</b> A60.

Line

1	that are scheduled for conversion over the next five years or those having existing
2	SCADA technology. For 2023 the Company is planning to install 190 remote-
3	operating reclosers on locations based on the prioritization method discussed
4	above. The Company forecasts it will be able to install over 300 remote-operating
5	reclosers each year through 2026. A discussed earlier in my testimony, the 4.8kv
6	circuit automation investment is appropriate for the Distribution IRM because it is
7	a key safety and reliability program and a process for sharing progress with the
8	Commission Staff.

10 Grid Automation Telecommunications

## 11 Q61. What is the Grid Automation Telecommunications program?

12 A61. The Grid Automation program addresses current telecommunication gaps by 13 deploying more modern infrastructure using advanced technologies. A modern and 14 advanced electric grid requires robust and secure communication channels which 15 is foundational to being able to operate the electrical system. This is described in 16 more detail in Section 3 of the Distribution Grid Plan (Exhibit A-23, Schedule M7), 17 which is based in part on the Department of Energy's (DOE) framework<sup>1</sup>. The 18 ability to transmit and capture real-time data in a highly reliable way is critical to 19 an advanced electric system because it enhances the ability to operate the grid 20 safely, reliably, and efficiently. Grid Automation telecommunications become 21 even more critical as EV and DER markets are forecasted to increase substantially 22 that require real-time communication to coordinate and optimize with the electrical 23 system.

24

<sup>&</sup>lt;sup>1</sup> Department of Energy Modern Distribution Grid Project next generation distribution system platform (DSPx) <u>PNNL: Grid Architecture - Modern Distribution Grid Project</u>

# Q62. Why is it important for the Company to invest and upgrade the Telecommunications system?

3 A62. The Company's existing fiber ring was installed decades ago to connect Company 4 data centers and stations on towers along transmission corridors. Its primary 5 purpose was to enable resiliency of data flow for critical Company operations; it 6 was not designed to connect more modern distribution resources, such as the 4.8kv 7 circuit automation devices discussed earlier in my testimony. Investment and 8 upgrades are reasonable and prudent because many current devices on the 9 Company's electrical system, including some pole-top and substation equipment, 10 are either not connected for remote monitoring and control, or are connected 11 through a communication network that is not fully integrated. The current 12 communication network is made up of diverse equipment and technology such as 13 fiber, microwave, leased phone lines, and radio. Furthermore, much of the 14 communication network currently available is only through a point-to-point 15 network that is less reliable than more modern and advanced mesh technologies. In 16 addition, some of the existing communication equipment must be replaced because 17 it is obsolete and spare parts are no longer available. Sufficient and reliable 18 bandwidth is critical and necessary to meet the current and growing requirements 19 of a modern electrical system and to allow the deployment of cybersecurity 20 protocols.

21

### 22 Q63. What is the scope of the Grid Automation Telecommunications program?

A63. The scope includes installation of a more modern telecommunication systems with
 bandwidth sufficient to support all anticipated usage and growth discussed in the
 Company's DGP. Upon full implementation, the Company will have upgraded and

1 installed approximately 630 miles of fiber and 30 routers for approximately 400 2 substations and other critical locations under the program. 3 Overhead fiber is being designed in a ring configuration so if damage occurs in one 4 section it does not result in an outage. The system upgrade includes technology with 5 fault locating capability that will be monitored in the SOC. Fault locating will notify 6 the SOC immediately when damage occurs to the fiber, with the location, to allow 7 for rapid repair. Additionally, as an ancillary benefit, the Company could be able to 8 identify other damage to the system in that area as damage to the fiber ring likely 9 means damage to other parts of the overhead electrical system.

10

#### 11 **Q64.** How will the fiber be constructed?

12 A64. Fiber construction will primarily be overhead and located in the communications 13 space above joint use on the pole. Overhead was selected for several reasons, but 14 the most significant factor was cost effectiveness. While Underground may provide 15 some incremental benefits in terms of risk of damage, the overhead approach 16 enables significantly more miles to be installed at a faster rate and for the same cost. 17 Overhead construction is the preferred method and standard in the 18 telecommunications industry to install more alternate paths to reduce single points 19 of failure rather than highly protecting a single path. Overhead construction costs 20 less than underground construction because it uses existing poles and right of ways 21 and the installation does not require specialized equipment or coordination of 22 different crew resource types. Underground sections are used only when necessary 23 and required. For example, a location with no existing pole infrastructure would 24 be placed underground.

25

#### Line No.

# 1 Q65. What progress has been made and what is the plan for upgrading the 2 telecommunication system?

- 3 A65. In 2021, approximately 27 substations and two service center microwave towers 4 with approximately 72 miles of fiber were connected through seven new routes in 5 Detroit, Downriver, Dearborn, Redford, Port Huron, Royal Oak and Troy. 6 Additionally, microwave tower transmitters and Wimax pole top transmitters were 7 replaced to mitigate Federal Communication Commission (FCC) frequency band 8 reallocations for Wi-Fi and 5G cellular. This was necessary because not replacing 9 this equipment would degrade the capability of the existing communication systems 10 to unacceptable performance levels. In 2022, 203 miles of fiber were installed 11 connecting 85 infrastructure locations in West Detroit, Dearborn, the urban I-96 12 corridor, Downriver to Monroe, northern Oakland County and northern Macomb 13 County. For 2023, approximately 230 miles of fiber connecting 100 substations 14 and other locations is planned in East Detroit, Dearborn, Downriver, Eastern Macomb County, Monroe County, Livingston County and northern Oakland 15 16 County.
- 17
- 18 **Q66.** How are the upgrades prioritized?

A66. The new fiber construction is prioritized based upon system criticality, automation, currently installed communication devices, the number of customers served, the existing infrastructure availability and reliability, and planned projects and programs. For example, subtransmission stations, peaker-plant locations, and service centers with microwave communications towers are considered high priority. The spacing between rings in the new fiber network is intended to provide sufficient coverage to allow for other end point solutions, such as the wireless mesh,

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<u>No.</u>

to be used at its optimal capacity. Routes are planned to link existing high bandwidth communication to these locations while also connecting distribution substations as part of this program. This means that areas with lower customer density will need more miles to reach.

5

## 6 Q67. What are the benefits of the Grid Automation Telecommunications upgrades?

7 A67. The ability to remotely control and operate critical reliability equipment benefits 8 our customers because it results in faster restoration time when they are without 9 power. The program will modernize the communication and cybersecurity network. 10 It will support remote monitoring and control of critical equipment including pole 11 top and substation devices. Currently these critical pieces of equipment cannot be 12 fully leveraged due to restricted or limited telecommunication bandwidth and 13 legacy serial protocols. The investments address these issues and enable the 14 equipment required to fully support increased functionality that will be integrated 15 by the Distribution Management System (DMS) within ADMS. The use of 16 technology to monitor and immediately control what is happening on the system is foundational to a modernized electrical grid. The ability to remotely control and 17 18 operate critical reliability equipment results in faster restoration time for customers 19 without power. When equipment fails on the electrical system, the technology 20 provides real-time information to the system operators. This information enables 21 system operators to identify the issue, execute switching operations, and 22 immediately dispatch the right crews resulting in faster outage restoration for our 23 customers. In addition, the transition from Microwave and Wi-Max to private fiber 24 lines reduces cyber risk pertaining to malevolent electromagnetic interference. 25 Additionally, degradation of service from interference caused by the recent FCC

<u>NU.</u>		
1		frequency auctions of these wireless communication bands to unlicensed public
2		use, creates even more interference and reduces the reliability and capability of the
3		wireless systems. Additionally, the traffic on the private fiber is limited to utility-
4		specific communications data, protocols, and devices which greatly improves the
5		ability to detect, isolate, and terminate any suspicious activity.
6		
7	]	Distribution Automation
8	Q68.	What is Distribution Automation?
9	A68.	As explained in the DOE report "Distribution Automation: Results from the Smart
10		Grid Investment Grant Program," published in September 2016, Distribution
11		Automation (DA) uses digital sensors and switches with advanced control and
12		communication technologies to automate feeder switching; voltage and equipment
13		health monitoring; voltage and reactive power management. Automation can
14		improve the speed, cost, and accuracy of these key distribution functions to deliver
15		reliability improvements and cost savings to customers.
16		
17	Q69.	What are the benefits of Distribution Automation?
18	A69.	Distribution automation technologies and Smart Grid Investment Grant Projects
19		discussed by the DOE, demonstrate how these technologies substantially benefit
20		the grid. The benefits include improved Fault Location, Isolation, and Service
21		Restoration (FLISR) capabilities, improved distribution system resilience to
22		extreme weather, more effective equipment monitoring and preventative
23		maintenance, more efficient use of repair crews, reduced repair times, and
24		improved grid integration of DER. Specifically, five utilities reported a 50-55%
25		reduction in the number of customer interruptions and customer minutes of

		B. L. HILL
Line <u>No.</u>		U-21297
1		interruptions per outage events during FLISR operations and three utilities reported
2		SAIFI improvements of 17-58% from pre-deployment baselines thanks to the
3		ability to more quickly identify the location of a fault and perform switching
4		activities that allow the fault to be isolated to a smaller area so that fewer customers
5		are impacted during the repair activities (Distribution Automation: Results from the
6		Smart Grid Investment Grant Program (energy.gov)).
7		
8		Distribution automation (automated field devices, advanced protection, SCADA),
9		is a core component for grid modernization, as discussed in the Company's 2021
10		DGP (Exhibit A-23, Schedule M7), and in the DOE's DSPx framework, referenced
11		in Exhibit 3.4.2.1 on page 53 of the DGP. Distribution Automation provides
12		immediate system benefits, while also supporting other functional capabilities that
13		can be added in the future as grid needs evolve.
14		
15	Q70.	What progress has the Company made on its Distribution Automation
16		program?
17	A70.	The Company has progressed in deploying distribution automation the past several
18		years. For example, the SmartCurrents program resulted in using advanced
19		technology that created its first generation of "smart circuits," that provided more
20		insight, control, and automation. The program retrofitted 11 substations and 55
21		circuits with remote monitoring and control devices. The learnings from the
22		program resulted in standardized designs for substation automation circuit
23		construction. It also helped establish the Company's standardized communications
24		and control protocol between field equipment and the ESOC.
25		

1 In addition, the Company developed a standardized panel design for substation 2 automation that involves replacing electromechanical relays with microprocessor 3 relays, as well as upgrades to the SCADA and telecommunications infrastructure. 4 Today, approximately 32% of general-purpose substations and 25% of the 5 distribution circuits in the Company's territory have SCADA monitoring and 6 control. Approximately 5% of the distribution circuits in the Company's territory 7 have automatic loop schemes, which can automatically transfer sections of the 8 circuits into adjacent circuits when an outage is detected.

9

#### 10 **Q71.** What is the scope of work for the Distribution Automation program?

11 A71. The scope of work will consist of substation automation and 13.2kV circuit 12 automation. Substation automation involves control panel replacements with 13 upgraded, standardized relays, installation of Remote Terminal Units (RTU), 14 incorporation of the RTUs and automation controls in the same substation network, 15 and breaker replacements as needed. 13.2kV Circuit automation involves installation of remotely controllable/automatic reclosers and sensing devices, 16 replacements of end-of-life automation devices that cannot be retrofitted, and 17 18 reconductoring as needed to enable circuit load transfer during outage conditions. 19 The automation technologies installed on substations and circuits will also be 20 linked to the ADMS for enhanced applications. These include, but are not limited 21 to, the FLISR application, which combines fault location information with the 22 circuit loading to optimize restoration and automatically restore service. It also 23 includes the Optimal Feeder Reconfiguration application, which analyzes load 24 transfer options that can be executed across multiple substations to manage system 25 loading conditions and improve system performance.

2 Q72. How many locations will be upgraded in 2023 and 2024?

3 A72. The scope of work for 2022 includes the design of full SCADA control and 4 monitoring of one substation as well as developing standards and processes that can 5 be utilized to accelerate the installation of distribution automation equipment across 6 the electrical system. In 2023 we plan to upgrade 6 substation positions to the 7 new standard and begin design on 22 of 66 units for 2024. In 2024 we expect to construct 66 upgraded positions in the field. For Distribution Automation 6 circuits 8 9 will be updated to current automation standards, including SCADA for all major 10 equipment and installation of automated switching and protection. In 2024, 12 11 circuits will be rebuilt using the updated distribution automation standards.

12

### 13 Q73. Are there any other considerations in implementing Distribution Automation?

- A73. Yes. Distribution Automation will be executed strategically to maximize customer
  benefits. Not all substations or circuits require distribution automation upgrades
  given circuit configuration, substation physical constraints, and cost effectiveness
  of the program. For example, some 4.8kV substations do not have the physical
  infrastructure (breakers, relays, etc.) therefore these locations are unable to support
  distribution automation control. Distribution automation will be deployed as these
  circuits are converted to higher grid voltages.
- 21

## 22 Non-Wires Alternatives (NWA) Pilots

#### 23 Q74. What are Non-Wires Alternatives?

A74. Non-Wires Alternatives (NWA) are defined in Section 4.3 of the DGP, which is included as Exhibit A-23, Schedule M7, (using the definition from Case No. U-

2

3

4

20147) as: "An electricity grid investment or project that uses distribution solutions such as distributed energy resources (DER), energy waste reduction (EWR), demand response (DR), and grid software and controls, to defer or replace the need for distribution system upgrades."

5

## 6 **Q75.** Why is the Company evaluating NWA?

7 A75. The August 20, 2020 Order in Case No. U-20147 ("August 2020 Order") stated on 8 pages 43 and 44 that "the Commission expects to be presented with 'a robust suite 9 of NWAs that may be evaluated for prudency as possible programs." Consistent 10 with that Order, the Company has developed a suite of NWA pilots, and in some 11 cases, implemented through the pilots' alternative technologies to address circuit 12 or substation overload concerns to help delay or offset traditional system upgrades. 13 The Company is interested in further developing these alternatives and evaluating 14 the pilot results to better understand customer benefits and costs as part of the 15 longer-term grid modernization plan. This is also consistent with the industry's 16 evaluation of the opportunities that NWA's present.

17

# Q76. Were the Company's plans for complying with the NWA aspects of the August 2020 Order presented in MPSC Case No. U-20836?

A76. Yes. The Company presented a suite of NWA pilots in MPSC Case No. U-20836.
My testimony will discuss and provide updates on the NWA pilots. The pilot
update will include project details, lessons learned, next steps, and address specific
points on the Company's NWA plan included in the Order from MPSC Case No.
U-20836. The Order provided specific feedback on each pilot. That feedback is

Line		<b>B. L. HILL</b> U-21297
<u>INO.</u> 1		summarized in Exhibit A 12 Schedule P5 4.0 with the Company's response in the
1		summarized in Exhibit A-12, Schedule B5.4.9 with the Company's response in the
2		instant case.
3		
4	Q77.	What is the Company's objective for NWA?
5	A77.	The Company's objective is to incorporate NWA solutions into the distribution
6		planning process to be considered along with traditional options to best meet the
7		planning objectives described in the Company's 2021 DGP on page 400, Exhibit
8		A-23, Schedule M-7. The pilots currently being pursued are building blocks, which
9		will form a foundation for future NWA projects. As capabilities are confirmed,
10		multiple NWA technologies can be combined to further advance the Company's
11		utilization of NWA.
12		
13	Q78.	What are the potential customer benefits of NWAs?
14	A78.	The expected benefit of an NWA project is to solve an immediate grid need, such
15		as a substation over its firm capacity, and to defer or reduce the scale of longer-
16		term infrastructure upgrades. As NWA customer benefits and the associated costs
17		become better understood through further development of pilot projects and use
18		cases, NWA projects have the potential to become economic alternatives compared
19		to traditional infrastructure upgrades. The pilots are expected to validate customer
20		and economic benefits to help further refine the analysis of NWAs as an alternative
21		to traditional solutions. While individual participating customers benefit from
22		investment in some of the technologies used in targeted NWA solutions, such as
23		lower energy bills due to EWR; customers overall may benefit from the deferred or
24		displaced investment in infrastructure.
25		

#### 1 Q79. Can you describe how the NWA pilots proposed in the DGP were identified 2 and developed? 3 A79. The DGP NWA pilots were identified through a screening process that ensures the 4 Company's engineers consider NWA options. Distribution Operations collaborates 5 with several DTE organizations with a goal of utilizing geographically targeted 6 EWR, DR, energy storage, solar, and other measures identify and develop options 7 to field test load relief and other key attributes. As the NWA pilots are implemented 8 and the benefits are evaluated, NWA alternatives will be built into the Company's 9 project development processes. 10 11 **Q80.** What are the NWA pilots DTE Electric is currently pursuing? 12 A80. There is currently a suite of nine NWA pilots. Some of the pilots are still under 13 evaluation while others are in progress or have been completed. The suite of NWA 14 pilots is shown in Table 5 with the use cases and technology the pilots are intended 15 to test. The Hancock pilot was completed and described in MPSC Case No. U-16 20836, and the remaining planned pilots are fully described in Exhibit A-12, 17 Schedule B5.4.1 to Exhibit A-12, Schedule B.5.4.7, Exhibit A-23, Schedule M6, 18 and the DGP, Section 12.7, starting at page 400, which is included as Exhibit A-23, 19 Schedule M7.



5

Line No.

# Q81. Can you elaborate on the technologies included in Table 5?

6 A81. Yes. Energy Waste Reduction (EWR) refers to replacing less efficient equipment 7 with more efficient equipment, which reduces overall electrical demand. Demand 8 Response (DR) refers to a shift or reduction in electricity usage by a utility customer 9 to help manage demand on the electrical grid during periods of peak demand. 10 Behind-the-Meter (BTM) refers to coordinating the participation of customer 11 equipment to reduce overall demand or provide other system benefits. Electric 12 Vehicle (EV) charging refers to coordinating the charging or discharging of EV equipment to provide electrical system benefits or avoid electrical system issues or 13 14 overloads.

15

1	Q82.	Can you provide more detail on the Company's NWA pilot projects?
2	A82.	Yes. Each pilot is described in detail in the following sections and Exhibit A-12,
3		Schedule B5.4.1 to Exhibit A-12, Schedule B.5.4.7, Exhibit A-23, Schedule M7,
4		and Exhibit A-23, Schedule M6 provide additional details.
5		
6		<u>O'Shea</u>
7	Q83.	Can you briefly describe the O'Shea Pilot?
8	A83.	Yes. A 1MW (1hr) Battery Energy Storage System (BESS) is being interconnected
9		at the O'Shea solar park. O'Shea is DTE owned 2MW solar array installed on
10		Chicago DC 1415 which has power quality concerns due to the intermittent nature
11		of solar generation. The Battery Energy Storage System (BESS) will help to
12		address these concerns.
13		
14	Q84.	What progress has been made for the O'Shea Pilot?
15	A84.	The below grade work at the site has been completed, concrete support pads have
16		been poured, and the battery housing has been installed. The controls have been
17		procured and are undergoing testing, and the site is ready to install the batteries.
18		The project has allowed the Company to create standard designs and to develop
19		operations and maintenance instructions. These learnings and the opportunity for
20		test compliance to standards will result in safety policies for the installation and
21		usage of battery systems. The pilot has further allowed for the development of
22		processes and practices for interconnecting battery systems at renewable sites.
23		

<u>No.</u>		
1	Q85.	What work remains to be completed for the O'Shea Pilot?
2	A85.	Installing and commissioning the batteries is the primary work remaining. The
3		control systems, communication infrastructure, new processes, standard designs,
4		and other aspects of the pilot will be fully verified once the batteries are installed;
5		and participation in the wholesale market will be tested in consideration of FERC
6		Order 841.
7		
8		Mobile Battery Trailer
9	Q86.	Can you briefly describe the Mobile Battery Trailer pilot project including the
10		customer benefits?
11	A86.	The Company is developing a mobile battery system to support customer
12		restoration. The mobile system consists of three trailers. Two trailers contain
13		batteries (DC battery trailers), and the remaining trailer contains an inverter and
14		system interconnection equipment (medium voltage trailer). The mobile battery
15		systems support customer restorations in several ways including siting in place of
16		traditional portable generators, supporting system requirements during shutdowns
17		or maintenance, or being deployed at substations or on circuits to reduce peak load
18		as part of a broader NWA project.
19		
20	Q87.	What progress has been made in 2022?
21	A87.	The DC battery trailers and integration of hazardous energy isolation of DC systems
22		has been completed. Significant engineering effort was needed to allow the battery
23		trailer system to operate in a mobile configuration. The initial vendor system was
24		

Line

modified and updated to support direct connection to the electric grid. The benefit 24 of directly connecting to the grid is to aid in customer restorations either by 25

1		providing power during an outage or allowing customers to remain in power while
2		repairs are being done. Enabling the battery system to be flexibly and quickly
3		deployed into a diverse set of locations on the distribution grid required adding
4		additional components, operating devices, and safety standards. The project also
5		presented challenges in striving to comply with updated fire protection standards
6		including NFPA855, UL9540, and UL9540A. In addition, safety procedures and
7		best practices for energy storage were identified through utility benchmarking.
8		
9	Q88.	What work is remaining for the Mobile Battery Trailer Pilot?
10	A88.	Design and integration of the medium voltage trailer components and controls are
11		in progress. The Mobile Battery Trailer Pilot requires testing the operational
12		integration and use of a battery system in multiple different configurations,

locations, and system conditions including supporting a substation load constraint,

operating in conjunction with solar, and as part of a microgrid. The battery system

will also be tested in different configurations with other distributed energy

14 15

16

13

- 17
- 18 <u>Omega</u>

resources.

## 19 Q89. Can you briefly describe the Omega pilot project?

A89. Yes. Two subtransmission lines feed Omega substation and both lines are
overloaded. There are several projects planned to address these conditions that will
be completed over the next few years. These projects will require shutdowns and
contingency plans to be completed to mitigate the risk of long duration and wide
scale outages. The placement of mobile storage equipment (the same equipment
described in the Mobile Battery Trailer section) at Omega substation will facilitate

the shutdowns and contingency plans enabling the work and project to be
 completed. When these subtransmission projects are completed and storage is no
 longer needed, the mobile batteries will be moved to other locations, for example,
 Port Austin.

5

#### 6 **Q90.** What work has been completed for the Omega Pilot?

A90. Engineering, design and construction were completed on-time and on-budget for
the site. Standards have also been developed to improve the efficiency of future
applications of storage for the same purposes. The Company learned technical
specifications and requirements to integrate battery storage equipment with the
electrical system in a safe and reliable manner.

12

#### 13 **Q91.** What work is remaining for the Omega pilot?

A91. Installation and commissioning the mobile storage equipment is expected to be
 completed by Q3 2023. Upon completion, the controls and protection can be fully
 tested. Additionally, the storage equipment will be installed using the
 commissioning process and include developing operational procedures for future
 use.

19

#### 20 **Q92.** Has the Omega pilot presented challenges?

A92. Yes. The Omega pilot is the first application at DTE Electric of energy storage used
to mitigate loading risk on the distribution system. This project required the
Company to search and identify a battery storage supplier and work with that
supplier to make the equipment ready for utility applications. Specifically, the
supplier had to prepare equipment that met the Company's safety requirements,
1		such as providing sectionalizing equipment and tagging points for maintenance and
2		operation. In addition, raw material availability was challenged by global supply
3		chain issues. This resulted in extended lead times and increased material and
4		shipping costs. To comply with the MPSC's Order to explore NWAs to address
5		traditional system issues, the Company's engineering team worked diligently to
6	5 meet these challenges and address the concerns at Omega substation through the	
7		pilot.
8		
9		Fisher
10	Q93.	Can you briefly describe the Fisher pilot?
11	A93.	Yes. Fisher substation is over its firm capacity rating by approximately 2.5MVA.
12		In addition, two circuits served by Fisher are expected to be over the 8MVA design
13		standard for a 13.2kV circuit. This poses significant risk of outages and not being
14		able to serve customers. The Company originally considered adding capacity at the
15		substation by upgrading from a Class "F" substation to a Class "A" substation,
16		replacing the existing transformers with 15/20/25MVA transformers, installing a
17		nine position Power Distribution Center (PDC), and adding two new circuits to split
18		the load. The Company considered NWA alternatives. The NWA scope includes
19		targeted deployment of Demand Response (DR) and Energy Waste Reduction
20		(EWR) to relieve a portion of the load concerns. The remaining load concerns at
21		Fisher will be addressed with the installation of a STDF (Subtransmission
22		Distribution Facility <sup>2</sup> ) in a 120kV corridor. This will allow one of the existing
23		circuits to be split. The combination of energy waste reduction, demand response,
24		and the STDF will address the loading concerns and return these circuits to their

 $<sup>^2</sup>$  A facility that consists of a set of equipment which creates a single circuit from a substransmission connection.

design capacity ratings. The progress, learning and next steps for each aspect of the
 project (EWR, DR and STDF portions) are described in the next portions of my
 testimony.

4

# 5 Q94. What has been the progress and results of the Energy Waste Reduction (EWR) 6 work at Fisher?

7 A94. The Company has been working on Energy Waste Reductions (EWR) in 8 collaboration with the MPSC and Natural Resources Defense Council. The team 9 continues to design and plan a cost-effective mix of pilot programs to deliver an 10 estimated 300 peak-kW reduction over the span of three years in the field. 11 Throughout 2022, the implementation team launched pilots including Residential 12 Appliance Recycling, C&I Prescriptive, Small Business, Lighting, HVAC and 13 Food Service. The Pilots include incentives to deliver off peak-load relief for 14 premises connected to Fisher circuits. Early EWR peak-load reduction progress for 15 year-end 2022 are reported at a 100 peak-kW reduction. This EWR pilot result 16 exceeded the 2022 original forecast. EWR has also continued working with the 17 MPSC and Natural Resources Defense Council along with the DTE Energy EWR 18 independent evaluator on an EM&V plan to adequately analyze and report results.

19

# Q95. What EWR work is still to be completed for the Fisher project and what is the expected timeline for that work?

- A95. The field pilot programs will run for three years. The pilot programs started in 2022
  and expected field implementation is forecasted September 2025.
- 24

Line

#### 1 Q96. Are the EWR costs included in Exhibit A-12, Schedule B5.4? 2 A96. No. Energy Waste Reduction pilot costs are included as part of the Company's 3 EWR Plan Case No. U-20876, Exhibit A-11 and Exhibit A-14. 4 5 **Q97.** What has been the progress and results of the DR work at Fisher? 6 A97. As of Q4 2022, there are a total of 149 customers at the Fisher substation enrolled 7 in the Smart Savers program. Based on analysis, these customers provide a total of 8 92 kW available in demand savings. The incremental participation can be attributed 9 to geotargeted marketing to eligible residential customers at the Fisher substation 10 offering an additional incentive for enrolling in the program. As of Q4 2022, there 11 are a total of 302 CoolCurrents customers online and operable at the Fisher 12 substation. Based on analysis, these customers provide a total of approximately 160 13 kW available in demand savings. In addition to the 302 online customers, Demand 14 Response has identified 199 CoolCurrents customers at the Fisher substation who 15 are offline because they do not have a proper 24-volt power source connection. 16 Letters have been sent to offline customers in an effort to have them fulfill their 17 customer requirement, at their own cost, and repair their 24-volt power source 18 connection. In addition, the Company has identified a solution that would not 19 require a 24-volt line and involves reconfiguring the current Load Control Device 20 (LCD). The Company plans to reconfigure 5,000 of the current LCDs and install 21 them in 2023 as a trial. The trial will be inclusive of the 199 offline CoolCurrents 22 customers at the Fisher substation. If deemed successful, the Company plans to 23 move forward with this approach. The Company also plans to actively market 24 current CoolCurrents customers who no longer want to be on the discounted rate,

Line		<b>B. L. HILL</b> U-21297
<u>No.</u>		
1		an alternative such as Smart Savers or SmartCurrents, in an effort to retain them as
2		a demand response customer.
3		
4	Q98.	What DR work is still to be completed for the Fisher project and what is the
5		expected timeline for that work?
6	A98.	The pilot was launched in 2022 and is forecasted to run for three years with field
7		implementation in September 2025. Demand Response will continue to deploy
8		enhanced marketing efforts for the Smart Savers program to drive incremental
9		enrollment. Demand Response will also continue efforts to restore offline
10		CoolCurrents customers.
11		
12		
13	Q99.	What has been the progress and next steps for the STDF ?
14	A99.	Preliminary engineering and design are completed. Reconductoring is expected to
15		start in early 2023 and final construction is expected to be competed in 2023. The
16		design for the STDF installation is forecasted to start in 2023, and the STDF will
17		be installed and operational in 2024.
18		
19		Port Austin
20	Q100.	Can you briefly describe the Port Austin Pilot?
21	A100.	Yes. Port Austin substation is over its firm rating, one circuit is over its day-to-day
22		rating, and there are short periods of low voltage at the end of the circuits during
23		periods of peak demand. The substation voltage is 4.8kV, and the traditional
24		method for addressing these concerns would be to convert the area to higher voltage
25		13.2kV. However, significant load growth is not forecasted in this area, which

1		makes this a lower priority for conversion compared to other areas. Additionally,
2		this area is vulnerable to severe weather and experienced two tornadoes in recent
3		years. With these considerations, the Company is piloting solar and storage to
4		address these concerns. Deployment of this equipment and using it to form a
5		microgrid will benefit and supply power to a portion of the customers on the circuits
6		if an event creates a fault that interrupts service from the substation.
7		
8	Q101.	What progress was made in 2022?
9	A101.	Engineering was completed and detailed design started. Purchasing the property
10		began and will be finalized in early 2023. The solar equipment was purchased and
11		will be delivered in early 2023.
12		
13	Q102.	What work remains for the Port Austin pilot?
14	A102.	Detailed design and construction need to be completed. The control systems,
15		communication infrastructure, new processes, standard designs, and other aspects
16		of the pilot will be fully verified once the batteries and solar are installed, and
17		participation in the wholesale market will be tested in consideration of the FERC
18		Order 841.
19		
20		Veridian
21	Q103.	Can you briefly describe the Veridian project?
22	A103.	Veridian is a planned development in Ann Arbor. The area is served by Regent
23		substation, which is a 4.8kV substation. While substation loading is not the primary
24		concern, the overall load of the development is expected to approach 1.5MVA, and
25		none of the existing circuits have capacity to accommodate this level of load

1		growth. However, the developer is planning to deploy customer owned solar and
2		storage. By carefully coordinating the usage of the customer deployed DER with
3		utility controls, system upgrades can be minimized yet still deliver safe and reliable
4		power required for this development. There are three aspects of the project:
5		
6		$\underline{\text{URD Loop}}$ – A three-phase URD loop will be installed in the subdivision to serve
7		the customers. The increased load growth at the site will require a three-phase URD
8		loop, where a single-phase loop is typically sufficient for most residential
9		subdivisions. The customer will pay for this service as would be the case with any
10		new residential development.
11		System Upgrades - This work is required to reconductor a portion of the
12		distribution backbone necessary to serve the increased load. Close coordination
13		with the customers' DER will minimize system upgrades.
14		
15		$\underline{\text{Microgrid}}$ – This work will install a utility scale battery, reclosers, and controls to
16		use the customer's DER and the Company's storage in a microgrid. This will
17		minimize the time customers remain without power if there is a substation or circuit
18		interruption due to a significant weather event.
19		
20	Q104.	What work remains to be completed for the Veridian Pilot?
21	A104.	Design is underway for the underground residential distribution (URD) and
22		reconductoring portions of the Veridian project. The URD loop construction is
23		currently scheduled to align with the developer's project plan, extending through
24		early 2023. The system upgrade portion of the project will begin construction in
25		2023 and will be completed in 2024. The Microgrid portion of this pilot is currently

in engineering study and is expected to be implemented beginning in 2024, aligning
 with occupancy of the development and the solar/storage DER components going
 on-line.

4

5

#### EV Charging Demo at ACM (American Center for Mobility)

#### 6 Q105. Can you briefly describe the EV Charging Demo at ACM?

7 A105. The ACM is a unique, purpose-built facility focused on testing, validation and self-8 certification of connected and automated vehicles and other mobility technologies 9 at the 500-plus-acre historic Willow Run site in Ypsilanti Township in Southeast 10 Michigan. The Company will leverage this charging network to get a better 11 understanding of the capabilities to control charging and predict the need for 12 charging from autonomous vehicles. DTE Electric is supporting the 13 implementation of the Delta Power Electronics DC Xtreme 400KW fast charger 14 and understanding the impacts of high-powered charging on power quality. The 15 DOE pilot program for DE-FOA-0002197, EVS-at-RISC (Electric Vehicle Secure 16 - Resilient Interoperable Smart Charging), will help the Company develop cyber secure monitoring and control capabilities with smart charge controls and inductive 17 18 road charging to ensure reliable and secure interfaces and will further enhance 19 knowledge of the grid impact of these new technologies. The pilot will install a 20 utility gateway and communications portal to enable charge management, develop 21 control algorithms and conduct testing on a Delta Extreme fast charger and its 22 interfaces, develop cyber security interfaces and control, install additional sensing 23 capabilities, and monitor performance on charging network, and develop 24 monitoring and control algorithms for in-road inductive charging at the ACM site.

25

Line No.

> 1 The initial Delta fast charger was available by the end of 2021, the second phase 2 awarded in 2022 and installation in late 2022 with a demonstration for the 3 Department of Energy showing 400KW charging on commercially available 4 vehicles and the use of a solid-state transformer. Ongoing testing will review the 5 power quality and charging profile of the device with implementation in 2023 of a 6 commercially available charger. Smart charge management will be implementing 7 in three phases through 2023 and 2024 at the DTE DER lab, ACM and a wide scale 8 demonstration site. It will be available during the later phases of the project for 9 wider testing. These projects are predominately research and development to 10 establish the capabilities of utilizing charge management on charge control in 11 extreme fast charging environments and the scope of evaluation with the 12 Department of Energy is to demonstrate technical feasibility and meet 13 demonstration milestones.

14

#### 15 Q106. What work has been completed for the EV Charging Demo at ACM?

16 A106. Site preparation, below grade conduit, foundations for equipment, installation of medium voltage switch for extreme fast charger isolation and communications and 17 18 control hardware have been completed. In addition, the Xtreme fast charge 19 successfully completed initial charging demonstrations in late 2022. The 20 demonstration provides experience with solid state transformer technology where 21 the EV charger Direct current is directly coupled to the medium voltage primary 22 system, allowing for higher charging rates and significant efficiency gains by 23 eliminating traditional transformation and secondary voltage wiring.

24

# Q107. What remaining work is required for the EV Charging Demo at ACM? A107. Demonstration of charge management and cyber security controls are still to be completed. When this is completed, the Company will evaluate the power quality impacts of 400kW charging events and the operation of solid-state transformers.

impacts of 400kW charging events and the operation of solid-state transformers. Analysis of in road charging impacts on power quality and assessments of managed charging and cyber security of managed charging in an environment with different types and capabilities of chargers will also be completed.

8

9

7

5

6

#### Adaptive Networked Microgrids

# Q108. Does the Company have plans to extend microgrids beyond what is being deployed at Port Austin?

12 A108. Yes. DTE Electric is exploring federal funding opportunities for microgrid 13 applications. Microgrids provide a mechanism to bring local DERs together to 14 provide solutions for resilience and reliability by becoming their natural 15 aggregation point. Microgrids form a unit that hosts loads and generation, that can 16 be connected or disconnected from the rest of the grid. Additionally, multiple 17 neighboring microgrids with adaptive boundaries can form larger multi-customer 18 microgrids. DTE Electric is exploring opportunities for federal funding from the 19 Infrastructure Investment and Jobs Act (IIJA) to expand the NWA deployments at 20 Port Austin and O'Shea to incorporate innovative new technologies like adaptive 21 networked microgrids to increase customer benefits from the deployed assets.

22

#### 23 Q109. Are these costs included in Exhibit A-12, Schedule B5.4?

A109. No. DTE Electric partnered with other organizations to develop a proposal to receive funding from DOE for this work. If the DOE accepts this proposal, the

Line	<b>B. L. HILL</b> U-21297
<u>110.</u> 1	Company will propose funding for its match of the federal dollars in a future rate
2	case. IIJA grants are discussed further by Witness Kryscynski.
3	
4	<u>CVR/VVO</u>
5	Q110. What is Conservation Voltage Reduction and Volt-Var Optimalization?
6	A110. Conservation Voltage Reduction (CVR), manages customer voltage levels in the
7	lower portion of the allowable voltage ranges, thus reducing system losses, peak
8	demand, or energy consumption. CVR is achieved by utilizing equipment such as
9	transformer load tap changers (LTC), overhead line regulators, and capacitor banks.
10	In addition, SCADA monitoring devices and line sensors are used to help manage
11	voltage levels to achieve optimal demand and energy savings.
12	
13	Volt Var Optimization (VVO) manages system-wide voltage levels and reactive
14	power flow to achieve specific operating objectives. The objectives include reducing
15	losses, managing voltage volatility due to intermittent renewable generation,
16	optimizing operating parameters, and/or optimizing power factors.
17	
18	Q111. Why is the Company evaluating and implementing CVR/VVO?
19	A111. The Company is continuing to evaluate and implement CVR/VVO because it is a
20	reasonable and prudent cost-effective way to offset to peak generation, as approved
21	by the Commission in Case No. U-20471 Integrated Resource Plan.
22	
23	Q112. What is the scope of work for the CVR/VVO program in 2022, 2023, and 2024?
24	A112. The Company installed CVR/VVO on two substation transformers and 12 circuits
25	in 2022. The Company has identified 14 substation transformer locations and 93
	BLH-69

<u>No.</u>	
1	circuit locations to install CVR/VVO in 2024, this list may be further refined based
2	on 2023 loading data. In 2023, the Company has temporarily halted the program to
3	allow for the ramp up of the 4.8kV Circuit Automation program.
4	
5	
6	Q113. What were the directives from the Order in Case No. U-20836 regarding the
7	CVR/VVO project?
8	A113. In Case No. U-20836 Order the Commission wanted to the Company to present:
9	1) Actual and projected capital expenditures for CVR for every year from 2019
10	through the test year;
11	2) Actual and projected O&M expenses for CVR for every year from 2019 through
12	the test year;
13	3) Annual energy savings;
14	4) Cumulative energy savings;
15	5) Annual customer cost savings;
16	6) Cumulative customer cost savings.
17	
18	Q114. Has the Company provided CVR/VVO benefits?
19	A114. Yes. As part of Case No. U-20471 the Company files an IRP Annual Report. This
20	report provides the benefits for the CVR/VVO program. The report is filed annually
21	in April and includes yearly data. In addition, the Company's current IRP, Case No.
22	U-21193, provides forecasted benefits of the CVR/VVO programs.
23	

1	Q115.	Is the Company proposing additional investments in CVR/VVO?		
2	A115.	Yes. The Company plans to continue to invest in CVR/VVO in 2024. Circuits have		
3		already been prioritized for inclusion in the CVR/VVO program and the Company		
4		believes that it is in the customers best interest to continue to install CVR/VVO		
5		devices on already identified locations.		
6				
7	Q116.	Did the Company include the CVR/VVO program in its integrated resource		
8		plan that was filed last year in Case No. U-21193?		
9	A116.	Yes. As noted above, the Company still intends to execute on the CVR/VVO		
10		program and expects ADMS to provide additional flexibility in circuits on which		
11		CVR/VVO can be applied.		
12				
13	Q117.	Does this complete your direct testimony?		
14	A117.	Yes, it does.		
15				

## STATE OF MICHIGAN

## BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)
DTE ELECTRIC COMPANY	)
for authority to increase its rates, amend	)
its rate schedules and rules governing the	)
distribution and supply of electric energy, and	)
for miscellaneous accounting authority.	)

Case No. U-21297

#### QUALIFICATIONS

#### AND

#### DIRECT TESTIMONY

#### OF

#### TAMARA D. JOHNSON

## DTE ELECTRIC COMPANY QUALIFICATIONS AND DIRECT TESTIMONY OF TAMARA D. JOHNSON

Line <u>No.</u>

1	Q1.	What is your name, business address and by whom are you employed?		
2	A1.	My name is Tamara D. Johnson (she/her/hers). My business address is One Energy		
3		Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate		
4		Services, (LLC).		
5				
6	Q2.	On whose behalf are you testifying?		
7	A2.	I am testifying on behalf of DTE Electric Company (DTE Electric or Company).		
8				
9	Q3.	What is your educational background?		
10	A3.	I earned an undergraduate degree in Business Administration with focuses on		
11		accounting and finance from the Detroit College of Business, and an MBA with a		
12		focus on global management from the University of Phoenix.		
13				
14	Q4.	What is your work experience?		
15	A4.	I have worked at DTE Energy since 2003 where I have held positions of increasing		
16		responsibilities in Corporate Services, Controller's Organization, and Customer		
17		Service.		
18				
19	Q5.	Do you hold any certifications or are you a member of any professional		
20		organizations?		
21	A5.	Yes, I am Green Belt certified and serve on both the Accounting Aid Society (AAS)		
22		and National Energy and Utility Affordability Coalition (NEUAC) Boards.		
23				
24	Q6.	What are your current duties and responsibilities?		

1	A6.	As Director of the Revenue Management and Protection (RM&P) group for DTE,		
2		I am responsible for the overall direction, strategy, leadership and management of		
3		collection, theft mitigation and low-income programs for DTE. The RM&P group		
4		is responsible for driving reduced uncollectible expense for DTE Electric and DTE		
5		Gas as well as optimizing the Energy Assistance funding for low-income		
6		customers. I am updated weekly on operational performance measures for		
7		Customer Service and receive regular updates on financial performance and		
8		strategic plans to improve all areas of the Customer Service Business.		
9				
10	Q7.	Have you previously sponsored testimony before the Michigan Public Service		
10 11	Q7.	Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?		
10 11 12	<b>Q7.</b> A7.	<ul><li>Have you previously sponsored testimony before the Michigan Public Service</li><li>Commission (MPSC or Commission)?</li><li>Yes. I have sponsored testimony in the following MPSC cases:</li></ul>		
10 11 12 13	<b>Q7.</b> A7.	<ul> <li>Have you previously sponsored testimony before the Michigan Public Service</li> <li>Commission (MPSC or Commission)?</li> <li>Yes. I have sponsored testimony in the following MPSC cases:</li> <li>Case No. U-20162 (DTE Electric 2018 General Rate Case)</li> </ul>		
<ol> <li>10</li> <li>11</li> <li>12</li> <li>13</li> <li>14</li> </ol>	<b>Q7.</b> A7.	<ul> <li>Have you previously sponsored testimony before the Michigan Public Service</li> <li>Commission (MPSC or Commission)?</li> <li>Yes. I have sponsored testimony in the following MPSC cases: <ul> <li>Case No. U-20162 (DTE Electric 2018 General Rate Case)</li> <li>Case No. U-20561 (DTE Electric 2019 General Rate Case)</li> </ul> </li> </ul>		
<ol> <li>10</li> <li>11</li> <li>12</li> <li>13</li> <li>14</li> <li>15</li> </ol>	<b>Q7.</b> A7.	<ul> <li>Have you previously sponsored testimony before the Michigan Public Service</li> <li>Commission (MPSC or Commission)?</li> <li>Yes. I have sponsored testimony in the following MPSC cases: <ul> <li>Case No. U-20162 (DTE Electric 2018 General Rate Case)</li> <li>Case No. U-20561 (DTE Electric 2019 General Rate Case)</li> <li>Case No. U-20642 (DTE Gas 2019 General Rate Case)</li> </ul> </li> </ul>		
<ol> <li>10</li> <li>11</li> <li>12</li> <li>13</li> <li>14</li> <li>15</li> <li>16</li> </ol>	<b>Q7.</b> A7.	<ul> <li>Have you previously sponsored testimony before the Michigan Public Service</li> <li>Commission (MPSC or Commission)?</li> <li>Yes. I have sponsored testimony in the following MPSC cases: <ul> <li>Case No. U-20162 (DTE Electric 2018 General Rate Case)</li> <li>Case No. U-20561 (DTE Electric 2019 General Rate Case)</li> <li>Case No. U-20642 (DTE Gas 2019 General Rate Case)</li> <li>Case No. U-20940 (DTE Gas 2021 General Rate Case)</li> </ul> </li> </ul>		
<ol> <li>10</li> <li>11</li> <li>12</li> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> </ol>	<b>Q7.</b> A7.	<ul> <li>Have you previously sponsored testimony before the Michigan Public Service</li> <li>Commission (MPSC or Commission)?</li> <li>Yes. I have sponsored testimony in the following MPSC cases: <ul> <li>Case No. U-20162 (DTE Electric 2018 General Rate Case)</li> <li>Case No. U-20561 (DTE Electric 2019 General Rate Case)</li> <li>Case No. U-20642 (DTE Gas 2019 General Rate Case)</li> <li>Case No. U-20940 (DTE Gas 2021 General Rate Case)</li> <li>Case No. U-20836 (DTE Electric 2022 General Rate Case)</li> </ul> </li> </ul>		
<ol> <li>10</li> <li>11</li> <li>12</li> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> </ol>	<b>Q7.</b> A7.	<ul> <li>Have you previously sponsored testimony before the Michigan Public Service</li> <li>Commission (MPSC or Commission)?</li> <li>Yes. I have sponsored testimony in the following MPSC cases: <ul> <li>Case No. U-20162 (DTE Electric 2018 General Rate Case)</li> <li>Case No. U-20561 (DTE Electric 2019 General Rate Case)</li> <li>Case No. U-20642 (DTE Gas 2019 General Rate Case)</li> <li>Case No. U-20940 (DTE Gas 2021 General Rate Case)</li> <li>Case No. U-20836 (DTE Electric 2022 General Rate Case)</li> </ul> </li> </ul>		

# Line

Ν	о.

## 1 Purpose of Testimony

2	Q8.	What is the purpose of your testimony in this proceeding?											
3	A8.	The purpose of my testimony is to:											
4		• Explain the details of	• Explain the details of the Company's Energy assistance program										
5		• Provide details of DTE's Low Income Self-sufficiency Plan (LSP)											
6		• Provide details of DTE's Low-Income Assistance (LIA) credits											
7		• Provide details on the	ne Rate Schedule D1.6 rate provision change										
8		• Provide details of D	TE's Residential Income Assistance credits (RIA)										
9		• Provide details of D	TE's Payment Stability Plan (PSP) pilot										
10		• Explain and support	• Explain and support the \$54.6 million of projected uncollectible expense										
11													
12	Q9.	Are you sponsoring any exhibits in this proceeding?											
13	A9.	Yes. I am sponsoring the following exhibits:											
14		Exhibit Schedule Description											
15		A-13 C5.8	Projected Operation and Maintenance Expenses										
16			Uncollectible Accounts										
17		A-32 W1	Assistance Disconnect Rates										
18		A-32 W2 Cohere Pilot Report											
19													
20	Q10.	Were these exhibits prepa	red by you or under your direction?										
21	A10.	Yes, they were.											
22													
23	Energ	y Assistance Program											
24	Q11.	What energy assistance pr	ograms does the Company provide to its customers?										

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1	A11.	The Company provides energy assistance programs to both low-income and non-
2		low-income customers. The Company's energy assistance programs include the
3		Affordable Payment Plan (APP) which is known as the Low-Income Self
4		Sufficiency Program (LSP) and Residential Income Assistance and Low-Income
5		Assistance (RIA and LIA) credits. For non-low-income customers, we provide
6		energy assistance through a 25% match of the Low-Income Home Energy
7		Assistance Program (LIHEAP) Direct Support program administered by Michigan
8		Department of Health and Human Services (MDHHS) as well as Energy Waste
9		Reduction (EWR) services. Additionally, to further understand and meet the energy
10		affordability needs of our customers, we have implemented the Payment Stability
11		Plan (PSP) pilot approved in the Case No. U-20929 Order. I will discuss all these
12		programs in further detail in my testimony.
13		

#### 14 Q12. What is the goal of the Company's energy assistance programs?

A12. The goal of the Company's energy assistance programs is to gradually reduce arrears owed while encouraging and supporting good payment habits and reducing consumption. This program structure leads to participants reducing their arrears over time and adopting a habit of making regular, affordable payments, albeit subsidized in the short term. The end goal is customers reaching self-sufficiency and being able to afford the actual costs of the energy they consume.

21

# Q13. What efforts has DTE Electric taken to maximize the benefits available to the greatest number of its most vulnerable low-income customers?

A13. The Company understands the challenges facing our low-income customers and
 utilizes both external and internal resources to proactively identify and assist our

Line No.

1 customers. Partnering with social service agencies, the Michigan Department of 2 Health and Human Services (MDHHS), and community action groups, DTE 3 Electric can identify and assist customers utilizing our current energy assistance 4 programs as well as generate and collaborate on effective strategies for future 5 programs. Internally, the Company is continuously improving how we engage and 6 guide our customers to the right paths for energy assistance. 7 8 014. What external collaborations would further maximize benefits to low-income 9 customers? 10 A14. The Company is currently working through the Energy Affordability and 11 Accessibility Collaborative (EAAC) subcommittee recommendations for 12 streamlined energy assistance applications and a standardized partnership with the 13 state to leverage data-sharing similar to the process utilized with the Michigan 14 Department of Health and Human Services (MDHHS) during the LIHEAP direct 15 support initiative. This would allow DTE Energy and other utilities to identify 16 income qualified households and proactively provide pathways to energy assistance 17 like RIA credits and EWR services more efficiently. 18 19 Q15. Has DTE Energy participated in pilots or projects focused on process 20 improvement for getting energy assistance to income qualified customers? 21 A15. Yes, in 2019, DTE Energy, along with Consumers Energy, MDHHS, MPSC, and 22 Wayne Metro Community Action Agency participated in Project Cohere, a project 23 designed to streamline the process for energy assistance in Michigan. 24 25 Q16. What were the outcomes of Project Cohere?

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A16.	The project was successful in identifying solutions for a more streamlined process
	for delivering energy assistance to the most vulnerable customers. "By Spring 2020,
	Project Cohere had completed energy assistance eligibility determinations for 104
	households across the state of Michigan, with the average household facing an
	average of \$891 in arrears on their utility bill. Overall, the pilot demonstrated that
	applications processed through Project Cohere were complete far more quickly and
	successfully than traditional applications. The streamlined process provided relief
	for frontline staff while helping residents build momentum towards financial
	stability." The pilot was able to reduce household application time from 45-60
	minutes to less than 10 minutes and processing normally requiring 30 days or longer
	to complete had 97% of applicants enrolled to receive State Emergency Relief
	(SER), the same day. See exhibit A-32 W2 for Witness T. Johnson.
Low 1	Income Self-Sufficiency Program (LSP)
Q17.	What does the Company consider its key Affordable Payment Plan?
A17.	LSP is the Company's APP. It is a 2-year payment plan for vulnerable families to
	A16. <u>Low I</u> Q17. A17.

17 make affordable monthly payments based on income and energy usage. The 18 Company partners with social service agencies and the state of Michigan allowing 19 it to support and promote LSP. The LSP program provides comprehensive support 20 that helps eligible customers afford their utility service. The comprehensive support 21 includes wrap-around services from agency partners in the form of education, 22 energy efficiency, and other self-sufficiency services over the course of their 23 participation. While participating in the plan, customers have the benefit of 24 sustained energy. The plan eliminates any future late payment charges, and past 25 due energy charges are frozen while the customer receives a monthly arrears

Line <u>No.</u>		<b>T. D. JOHNSON</b> U-21297											
1		forgiveness credit. Additionally, a dedicated team of customer advocates within the											
2		Company are ready to assist customers while enrolled in LSP.											
3													
4	Q18.	What are the eligibility criteria for LSP candidates?											
5	A18.	A customer's household income must be equal to or less than the 150% federal											
6		poverty level (FPL). In addition, the customer's monetary value of annual energy											
7		consumption cannot exceed \$1,600 for electric, \$2,150 for gas, and \$3,750 for											
8		combined accounts. A customer's account must be active and have less than \$3,000											
9		of arrears at time of enrollment. Additionally, the candidate must be approved for											
10		State Emergency Relief (SER) before being enrolled in LSP.											
11													
12	Q19.	How does the Company measure success for the current LSP program?											
13	A19.	An LSP household is successful if the customer achieves a zero arrears balance by											
14		the end of the 24-month program. The Company refers to this population of											
15		enrollees as graduates. Additionally, customers who can meet their bill payments											
16		and not be removed from their term of enrollment is another measure of success.											
17													
18	Q20.	What are the Year Over Year (YOY) success metrics for LSP since its											
19		implementation?											
20	A20.	Table 1 depicts the metrics for LSP since its inception in 2013. This measure is											
21 22		customers avoiding disconnect due to missed payments.											
23		Table 1LSP Success Rate 2013-2022											

LSP Yr	2013	2014	2015	2016	2017	2018	2019*	2020**	2021	2022
Success										
Rate	80%	81%	92%	88%	91%	89%	67%	85%	82%	81%

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- <u>No.</u>

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- \*First year State Emergency Relief was required as part of the LSP enrollment eligibility
- 2 \*\* First year of 24 month LSP due to APP Alignment changes
- 3

## 4 Q21. How many households that graduated from LSP returned to the program?

5 A21. Over the past seven years, on average approximately 16% of graduates return to the
6 LSP program as shown in Table 2.

7

8

Table 2   LSP Graduate Metrics											
			Grad	Number		Eligible for					
LSP Yr	Enrolled	Grad	Percentage	Returned	Return %	Graduation					
2015-16	35,089	4,474	13%	1,189	27%	35,089					
2016-17	40,049	4,278	11%	1,315	31%	40,049					
2017-18	34,344	1,881	5%	93	5%	34,344					
2018-19*	36,109	4,877	14%	573	12%	36,109					
2019-20**	16,306	-	0%	-	0%	N/A					
2020-21	23,511	1,756	67%	178	10%	2,642					
2021-22	26,097	5,631	74%	611	11%	7,578					

9 \*First year SER was required as part of the LSP enrollment eligibility

10 \*\*Excluded due to first year of moving from a 48 month to 24-month LSP payment plan

11 due to APP Alignment changes

12

## 13 Q22. What ways are customers eligible for graduation from LSP?

A22. Prior to the 2019-20 fiscal year LSP graduates were selected based on their account
balance at the end of the fiscal year and not based on their time on the program. In

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1

the current program format customers are provided 24 months of eligibility on the program and graduation occurs the day after that eligibility ends.

3

2

4

5 Q23. Why do some low-income households return to the program after graduating? 6 A23. Once a customer has left the support of LSP, they may find themselves 7 experiencing challenges making consistent monthly payments and experience 8 another crisis. Additionally, customers on a fixed income struggle as they face 9 various challenges sustaining energy presents. Minimum wage workers struggle 10 with challenges to pay bills. A single customer who makes minimum wage, \$10.10 11 per hour in Michigan in 2023, will have an Adjusted Gross Income of \$19,401 12 (\$10.10 \* 2040 less 7.65% SS and Medicaid tax). The 2023 FPL for a single person 13 household is \$13,590 resulting in a 150% of FPL of \$20,385. According to the 14 Massachusetts Institute of Technology Living Wage Calculator, a living wage for 15 an individual living in the Detroit – Warren – Dearborn area is 33,705.<sup>1</sup> If the 16 Bureau of Labor Statistics 2020 estimate that approximately one percent of full-17 time workers nationwide were paid federal minimum wage or less is applicable to 18 DTE's customer base, at least one percent of our customers do not make the income necessary to pay all of their bills to live in the area.<sup>2</sup> These customers and customers 19 20 who make up to approximately 250% of FPL will consistently be unable to pay all 21 of their bills. These customers will be unable to be self-sufficient unless they are 22 able to increase their income levels. "From 2010 to 2019 Michigan showed steady 23 economic improvements according to traditional measures. Unemployment fell to

<sup>&</sup>lt;sup>1</sup> Living Wage Calculator - Living Wage Calculation for Detroit-Warren-Dearborn, MI (mit.edu) available at <u>https://livingwage.mit.edu/metros/19820 accessed on January 17</u>, 2023.

<sup>&</sup>lt;sup>2</sup> Characteristics of minimum wage workers, 2020 : BLS Reports: U.S. Bureau of Labor Statistics available

at https://www.bls.gov/opub/reports/minimum-wage/2020/home.htm accessed on January 17, 2023.

1 historic lows, GDP grew, and wages rose slightly. Yet in 2019, nine years after the 2 end of the Great Recession, 38% of Michigan's 3,963,558 households still 3 struggled. And while 13% of these households were living below the Federal 4 Poverty Level (FPL), another 25% - nearly twice as many - were ALICE 5 households: Asset Limited, Income Constrained, Employed. These households earned above 150% FPL, but not enough to afford household necessities."<sup>3</sup> These 6 7 types of scenarios stress the importance of exploring affordable payment options 8 that go beyond 24 months and even beyond the 150% FPL requirements. The PSP 9 pilot is an option to address long term energy affordability, which I speak to later 10 in my testimony.

11

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# Q24. What new initiatives is the Company undertaking to create comprehensive energy assistance for its low-income customer population?

A24. As a result of the Case No. U-20561 Order and approval of the Case No. U-20929
ex-parte filing, the Company launched the Payment Stability Plan (PSP) pilot in
January 2022. PSP is the Company's percentage of income payment plan (PIPP).

17

#### 18 **Q25.** What are the details of the PSP pilot?

19 A25. The PSP pilot is a percentage of income-based program directed at low-income 20 customers at or below 200% FPL. PSP is a 2-year pilot that started in the first 21 quarter of 2022. The pilot focuses on the importance of affordable energy as it 22 relates to energy burdens for low-income customers. Customers who receive either 23 gas or electric utility service from DTE Gas or DTE Electric have a flat bill payment 24 equivalent to 6% of the household gross income. Customers who receive both gas

<sup>&</sup>lt;sup>3</sup> ALICE In Michigan: A Financial Hardship Study, Live United 2021 Michigan Report, pg. 1, available at <u>https://www.unitedforalice.org/michigan</u>, accessed January 17, 2023.

Line

<u>No.</u>										
1		and electric utility service from the Con	mpanies have a fla	at bill payment e	quivalent					
2		> 10% of the household gross income. PSP enrollees are also contacted to receive								
3		EWR education services and provided	WR education services and provided partner agency information to receive wrap							
4		around services such as financial literacy, housing and food assistance, job and								
5		education development, children and family services, and transportation.								
6										
7	Q26.	What are some of the early outcomes	s of the pilot?							
8	A26.	Early stages of the pilot are already pr	resenting positive	outcomes. For	example,					
9		PSP households have improved on time	e bill payments by	over 16%, whic	h leads to					
10		direct month over month impact on arrears reduction and program benefit								
11		incentives. Developing analysis could show this as an indicator of improved energy								
12		affordability. The Company is currently working with Staff on standard reporting								
13		structure analyzing opportunities for long term implementation.								
14										
15		A component of PSP includes partnering enrollees with the Company's EWR								
16		services. During the first year of the pilot, 33% of PSP customers with single family								
17		housing units have been engaged via telephone, email, and postcards for EWR								
18		services. More than 10% of those customers scheduled appointments for energy								
19		efficiency analysis. The Company anticipates further work to increase engagement								
20		including developing solutions to impa	ct multi-family ho	ousing units as w	ell.					
21		Table 3	PSP Metrics	Γ	1					
			On-time payment %	Usage						
		12-month average prior to PSP enrollment	80.5%	732.5 kWh						
		2022 PSP average	96.7%	721.9 kWh						

22

#### Line No.

#### 1 Q27. What is the FPL breakdown of households enrolled in the PSP pilot?

2 A27. As stated earlier in my testimony, there are households with an FPL greater than 3 150% who are in need of pathways for affordable energy. One of the key points of 4 the pilot was to provide affordable payment plans to those households above 150% 5 FPL. The table below is aligned with DTE's APP FPL tiers. See Table 4 for FPL 6 range counts.

> Table 4 **PSP Household FPL** FPL Range Customer Percentage % <=20% 1% 21-75% 5% 76-110% 14% 43% 111-150% 151-200% 37%

7

8

#### 9 **Residential Income Assistance and Low-Income Assistance Credits**

#### 10 Q28. What other methods of assistance are there for low-income customers?

- 11 A28. Another key program addressing energy sustainability for our low-income 12 customers is the RIA and LIA assistance credits.
- 13

#### 14 What are the current key features of the RIA credit? Q29.

15 A29. The RIA credit offers low-income electric customers \$8.50 per month credit on 16 their bill. To be eligible, the total household income cannot exceed the 150% FPL,

- 17 verified by confirmation of an authorized State or Federal agency. The credit is
- 18 renewed annually based on the eligibility requirements. Customers may not receive
- 19 both an electric RIA and electric LIA credit at the same time.

Line <u>No.</u>		<b>T. D. JOHNSON</b> U-21297
1		
2	Q30.	How can a customer become enrolled to receive the electric RIA credit?
3	A30.	Customers who receive energy assistance in the form of a Home Heating Credit
4		(HHC), State Emergency Relief (SER), or one time assistance are automatically
5		enrolled to receive the RIA credit.
6		
7	Q31.	How does a customer who is not a recipient of the above-mentioned energy
8		assistance able to be enrolled to receive the RIA credit?
9	A31.	Households that do not receive energy assistance in the form of HHC, SER, or one
10		time assistance by an agency may provide documentation validating their eligibility
11		and be manually enrolled.
12		
13	Q32.	How does DTE Electric reach out to households not automatically enrolled for
14		the RIA credit?
15	A32.	We have several ways that we reach customers who may have a need for the
16		assistance. We distribute the "Payment Assistance Programs" brochure annually,
17		as required by the Commission. This brochure includes several options for energy
18		assistance and payment plans. Additionally, the brochure is also available on our
19		website for quick access. Both our virtual Customer Assistance Days (CADs) and
20		in-person Customer Resource Events also assist customers by providing a variety
21		of options to lower energy burden and provide pathways to EWR resources to lower
22		monthly payments. In addition to these communication touch points, our call center
23		analysts are trained to inquire and guide our customers to the best options for them
24		to sustain energy through our Agent Assist Tool, which is highlighted later in my
25		testimony.

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<u>No.</u>														
1														
2	Q33.	In 2022	2 how r	nany D	TE Ele	ectric cu	ustome	rs recei	ved the	e RIA c	redit?			
3	A33.	Over 1	Over 120,000 unique electric customers received the RIA credit in 2022 with an											
4		annual	nnual monthly average of 71,829.											
5			Table 52020-2022 Electric RIA Customer Counts											
	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg
	2020	40,841	31,153	42,712	36,033	34,226	37,229	38,366	40,914	40,240	42,742	42,660	51,284	39,867
	2021	49,353	47,625	59,867	59,242	56,920	70,009	60,730	60,095	57,133	54,675	52,637	54,668	56,913
	2022	55,273	52,472	77,861	64,098	71,279	76,710	70,158	80,906	75,554	77,992	76,119	83,522	71,829
6		Note: Cust	omer count	s are billing	g period en	d of month	snapshots	and year en	d variance	s to Part III	reporting c	lue to timin	ıg.	
7														
8	Q34.	How m	any RI	A custo	omers i	s the Co	ompan	y incluc	ling in	its proj	ected to	est year	?	
9	A34.	The Co	ompany	is forec	asting	the RIA	credit	enrollm	ent mo	nthly av	verage o	of 70,00	00	
10		custom	ers in tl	ne proje	cted tes	st year.								
11														
12	Q35.	What i	s the k	ey featu	ire of L	JA Cre	edit?							
13	A35.	The LI	A credi	t (conta	ained in	Rate S	Schedul	e D1.6)	) offers	qualify	ing lov	v-incom	ne	
14		electric	custon	ners a \$4	40 per 1	nonth c	redit or	their b	ill.					
15														
16	Q36.	What o	What currently makes a customer qualified to receive the LIA credit?											
17	A36.	To qua	To qualify for this rate an electric customer must have a total household income at											
18		or belo	or below 150% FPL.											
19														
20	Q37.	Can ai	ıy qual	ifying	low-inc	ome cu	istomei	curre	ntly be	eligibl	e to re	ceive th	ne	
21		LIA cr	edit?											

		T. D. JOHNSON
Line <u>No.</u>		U-21297
1	A37.	Yes, though the Company prioritizes customers who are enrolled in the Company's
2		APP or may be already receiving the RIA credit.
3		
4	Q38.	How many DTE Electric customers are currently enrolled and receiving the
5		electric LIA credit?
6	A38.	Over 47,000 unique households receive the LIA credit with an annual monthly
7		average of 32,167.

8

Table 62020-2022 Electric LIA Customer Counts

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg
2020	25,038	20,297	24,597	22,928	23,337	26,073	26,551	26,296	26,268	26,431	23,998	28,748	25,047
2021	25,896	24,025	29,348	27,369	26,226	30,633	27,769	29,214	27,950	26,250	27,888	33,852	28,035
2022	33,841	28,554	36,381	31,150	32,757	34,291	30,513	33,697	31,136	31,126	29,700	32,852	32,167

9

Note: Customer counts are billing period end of month snapshot and year end variances to Part III reporting fall within 5%.

10

#### 11 Q39. What is the enrollment process for the LIA credit?

12 A39. There are several ways a customer may receive the LIA credit.

13	1.	Customers	who	become	enrolled	in	the	LSP	program	are	also	enrolled	to
14		receive the	LIA o	credit.									

# Graduates of LSP may continue to receive the LIA credit if maintaining their low-income eligibility status.

- At the Company's discretion, customers receiving the RIA credit can transition
   to LIA when there is availability.
- Aligning the LIA credit with LSP helps our most vulnerable customers move
   toward self-sufficiency. Though non-LSP customers may also receive the LIA
   credit, experience has shown that applying the low-income credit first towards a

Line		T. D. JOHNSON
<u>No.</u>		0 212)7
1		long-term program yields the highest self-sufficiency and assists in preventing
2		missed payments.
3		
4	Q40.	What would be the impact if the LIA credit was applied randomly instead of
5		strategically paired with customers enrolled in the LSP program?
6	A40.	In previous case filings we have proven out that random application of the LIA
7		credit is not as effective as when customers are partnered with the LSP Program.
8		Random application results in higher disconnect rates amongst those customers
9		who do not have the additional support of an affordable payment plan such as LSP.
10		Overall, customers receiving the LIA credit without the pairing of LSP have twice
11		the disconnect rate as those receiving both LIA and LSP. See Exhibit A-32
12		W1.Lines 2,5,7, and 8 of the exhibit depicts non-LSP households receiving some
13		type of assistance such as Michigan Energy Assistance Payment (MEAP), HHC,
14		and RIA and the associated disconnect rates. LSP households receiving LIA
15		represent a significant decrease in the number of disconnects.
16		
17	Q41.	Is the Company proposing any changes to the LIA program?
18	A41.	Yes. As described in the testimony of Company witness Mr. Willis, the Company
19		is proposing to eliminate Rate Schedule D1.6 and to expand the availability of the
20		credit to all base residential rate schedules. This change will have no substantive
21		impact on the credit and will bring it in line with how the electric RIA is managed.
22		
23	Q42.	What is LIHEAP Direct Support?
24	A42.	The LIHEAP Direct Support assists eligible low-income households with their
25		heating and cooling energy costs, bill payment assistance, energy crisis assistance,

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1		weatherization, and energy-related home repairs. In 2022, in partnership with the
2		Michigan Department of Health and Human Services (MDHHS) and as part of the
3		Coronavirus Aid, Relief, and Economic Security (CARES) Act, the Company used
4		match-funding to reduce the arrears in the amount of \$4.9 million for nearly 10,000
5		low- and moderate-income households. The total LIHEAP Direct Support program
6		supported over 54,000 households and provided nearly \$25 million in energy
7		assistance. This collaboration required swift action in defining and identifying
8		eligible customers as well as a team effort in the coordination of communication
9		and system enhancements.
10		
11	<u>Uncol</u>	lectible Expense
12	Q43.	What is Uncollectible Expense?
13	A43.	Uncollectible expense is the income statement impact of recognizing a reserve for
14		the portion of accounts receivable that is considered uncollectible.
15		
16	Q44.	How is uncollectible expense determined?
17	A44.	Uncollectible expense is determined by a review of individual arrearage accounts
18		for the Company, recorded separately based on actual uncollectible performance
19		and as a reserve against accounts receivables.
20		
21	Q45.	How does DTE Electric determine the accounts receivable (AR) reserve for
22		uncollectible accounts?
23	A45.	DTE Electric uses a balance sheet method. The AR reserve is calculated by
24		applying reserve factors to aged receivables. Customer accounts receivable are
25		classified in 30-day increments (arrears buckets) and a reserve factor is applied to

## TDJ-17

each 30-day increment. The sum of these reserve values represents the total AR reserve. The Uncollectible Expense Calculation is shown in Figure 1.

The reserve factors are recalculated monthly using a rolling average of the ratio of historical write-offs to historical arrears within each arrears bucket (30, 60, 90, etc.). A 12-month rolling average is utilized for residential and small commercial accounts and a 60-month rolling average is utilized for large commercial and industrial accounts.



<sup>10</sup> 

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#### 12 Q46. How does the Company account for uncollectible expense?

13 A46. Uncollectible expense is recorded in the income statement to reflect the change in 14 the AR reserve. This is calculated as the required increase/decrease in the AR 15 reserve based on the aging analysis just described, plus accounts that were written-16 off that month, minus accounts that were recovered (on previously written off 17 accounts) that month, plus any DTE Electric matches of low-income funding 18 received.

19

<sup>11</sup> 

Line No.

#### 1 **Q47**. What are the Company's write-off procedures?

2 A47. Routine customer accounts are generally written off once they age to 150 days past 3 the final bill due date, which is issued after service is disconnected. Often, 4 however, there are circumstances that warrant keeping the account on the books 5 until a resolution is obtained – for example, customers with payment arrangements, 6 disputes, etc. Once an account is written off, any payments received on that account 7 are recognized as a recovery. The write-off period of 150 days past the final billing 8 is generally defined as the latest of either the last effective closed agreement date 9 or the last bill due date.

10

#### 11 **O48**. How is uncollectible expense calculated in this instant case?

12 In this instant case the Company is utilizing a three-year average based on actual A48. 13 uncollectible expense for 2019-2021, resulting in \$54.6 million of projected 14 uncollectible expense. This amount is calculated on Exhibit A-13, Schedule C5.8 15 and shown on line 1, column (e) of that same exhibit. The \$54.6 million projected 16 amount reflects the impacts of lower projected energy assistance and higher energy 17 prices when compared to the 2021 historical test year of \$36 million. The amount 18 of state and federal assistance in 2022-2023 is expected to return to pre-pandemic 19 levels (approximately 40% lower than aid available in 2021-2022).

20

#### 21 Q49. Why does the Company prefer a 3-year average over the cash basis 22 methodology utilized by Staff?

23 A49. The cash basis method for estimating uncollectible expense is inconsistent with 24 how expense is recorded and with how other costs and revenues are calculated for 25 both MPSC reporting and ratemaking. The Company determines uncollectible Line No.

> 1 accounts expense based on an accrual method as required by the Uniform System 2 of Accounts (USofA); General Instruction number 11. Rates are set to cover the 3 Company's expenses expected to be recorded for account purposes. The estimation 4 of future expenses should therefore be consistent with the practice used to record 5 the actual expenses to ensure recovery of the Company's prudent and reasonable 6 costs. An average of the amounts charged to account 904 provides such 7 consistency. In addition, the cash basis method does not factor in special 8 circumstances that are accounted for under the accrual method. For example, the 9 write-off of some accounts is delayed because they are being disputed or negotiated 10 and must remain open in the billing system until a final decision is made. Another 11 example is the decision to temporarily suspend disconnects during 2020 due to the 12 pandemic which drove a significant temporary decline in write-offs. The balances 13 in these examples are expected to be charged-off, so under the Company's accrual 14 method they are fully reserved. These situations would not be reflected in the cash 15 basis method. In addition, direct charges relating to the Company's forgiveness match to low-income customers (LSP and LIHEAP support) must be included in 16 17 uncollectible expense. These direct charges related to customer assistance are not 18 accounted for as write-offs; however, they are included in uncollectible expense 19 and reduce the probability that these customers will be disconnected, and the 20 associated balances will be written-off.

21

#### 22 Q50. What is the Company's historical net Charge-offs from 2019-2021?

A50. Figure 2 below provides the net Charge-offs from 2019-2021.

- 24
- 25
- 26

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Figure 2	Net Ch	narge-offs (20	19-2021)		
Description		2019	2020	:	2021
Write-offs	\$	107,564,349	79,896,130	\$	76, 776, 300
Collections		(35,771,421)	(30,169,706)	(	36, 732, 295)
Net Write-offs	\$	71,792,927	49,726,424	\$	40,044,005
Charges Directly to Expense		2,944,560	2,780,072		(145,979)
Net Write-offs including direct expense	\$	74,737,487	52,506,496	\$	39,898,026

2 3

#### 4 Q51. What events may impact uncollectibles in the projected test period?

A51. There are many factors that could impact or influence uncollectibles during the
projected test period. Though we continue to utilize our partnerships to take
advantage of all funding opportunities for our customers, unemployment rates, the
ending of extended benefits, and eviction moratorium could all impact
uncollectibles. Without continued state and federal assistance as provided in the
CARES Act and the Coronavirus Response and Relief Supplement Appropriations
Act of 2021, there is the potential that bad debt could materially increase.

12

# Q52. What actions is the Company taking to ensure that customers are aware of available energy assistance?

A52. The Company continues to inform customers of available energy assistance through
the standard channels such as 2-1-1 and information provided through digital
channels. In addition, the following accessibility strategies have been implemented:

18

21

- Outbound call campaign to SPP customers for SER application assistance
- Automated letter campaign to motivate potential energy assistance eligible
   customers to seek assistance early to avoid service interruption
  - Email blasts to past recipients of SER funding

1	• Email outreach to customers receiving Notice of Intent (NOI) letters
2	Accessibility strategies focus on expanding the SER application process and
3	leveraging community partnerships, involving virtual webinars to raise awareness
4	and virtual CADs to promote MEAP and other energy assistance. Understanding
5	the possible mail delivery delays through the United States Postal Service (USPS),
6	the proactive NOI email initiative will notify customers more quickly and will help
7	to prevent service interruption.
8	
9 Q53.	Does this complete your direct testimony?

10 A53. Yes, it does.

Line

No.

## **STATE OF MICHIGAN**

#### **BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

In the matter of the Application of	)
DTE ELECTRIC COMPANY	)
for authority to increase its rates, amend	)
its rate schedules and rules governing the	)
distribution and supply of electric energy, and	)
for miscellaneous accounting authority.	)

Case No. U-21297

QUALIFICATIONS

AND

#### DIRECT TESTIMONY

OF

#### ALLEN J. KRYSCYNSKI
#### DTE ELECTRIC COMPANY QUALIFICATIONS AND DIRECT TESTIMONY OF ALLEN J. KRYSCYNSKI

Line <u>No.</u>

1	Q1.	What is your name, business address and by whom are you employed?
2	A1.	My name is Allen J. Kryscynski (he/him), and my business address is One Energy
3		Plaza, Detroit, Michigan, 48226 and I am employed by DTE Electric Company
4		(DTE Electric or Company).
5		
6	Q2.	On whose behalf are you testifying?
7	A2.	I am testifying on behalf of DTE Electric.
8		
9	Q3.	What is your educational background?
10	A3.	I earned a Bachelor of Science from the University of Michigan School of Natural
11		Resources and Environment with a dual concentration in environmental policy and
12		natural resource management. I also earned a master's degree in Business
13		Administration (MBA) from the University of Michigan.
14		
15	Q4.	Please summarize your professional experience.
16	A4.	I held several positions with ITC Holdings including Senior Regulatory Analyst
17		and a variety of positions within the Local Community and Community Affairs
18		team culminating as a Senior Local Government and Community Affairs
19		Representative. During my time at ITC Holdings, I worked on FERC and MISO
20		regulatory issues as well as represented ITC Holdings at community meetings to
21		gain approval for new transmission substations and transmission lines.
22		
23		I joined DTE Energy in 2014 as a Strategy and Corporate Development Associate
24		in the Corporate Strategy group. In this role, I did work on the initial Distribution
25		Operations (DO) investment strategy project to determine distribution grid

1 investment needs as well as work on DTE workforce projections and requirements 2 for both the Distribution Operations and Fossil Generation business units. In 2016, 3 I was appointed Manager of Distribution Operations Strategy and assumed 4 responsibility for continued work to evolve the distribution operations investment 5 strategy, operations strategy, and the chief of staff role for the Senior Vice President 6 of Distribution Operations. In early 2018, I was appointed Manager in Project 7 Management with responsibility to start up and operationalize the 4.8kV Hardening 8 Program to remove City of Detroit Arc Wire and harden the City of Detroit 9 electrical infrastructure. Later in 2018, I was appointed Manager of Tree Trim 10 Strategy where I was responsible for managing the initial Tree Trim Surge rate case, 11 Tree Trim contractor negotiations, and the overall Tree Trim strategy for 12 scheduling work, and ensuring there was an adequate supply of tree trimmers 13 necessary to complete the work. In 2020 I took over the Tree Trim Operations 14 Manager position and managed day to day Tree Trim operations including 15 overseeing all of DTE's internal arborists and foresters as well as eight tree trim contractors and their 1,600+ employees. In 2022 I was appointed to my current role 16 17 - Manager of Distribution Operations Regulatory Strategy and Grid Modernization.

18

#### 19 Q5. What are your current duties and responsibilities?

A5. As Manager of Distribution Operations Regulatory Strategy and Grid
Modernization, my current responsibilities include two primary focus areas: 1)
managing Distribution Operations regulatory activities – including rate cases, the
distribution grid plan filing, required reporting, and various Company/MPSC
collaboratives, and 2) Distribution Operations long term grid modernization
strategy and the distribution grid plan (DGP).

Line <u>No.</u>		<b>A. J. KRYSCYNSKI</b> U-21297
1		
2	Q6.	Have you previously sponsored testimony before the Michigan Public Service
3		Commission (MPSC or Commission)?
4	A6.	No. I have supported Tree Trim testimony and witnesses in U-20162, U-20561, and
5		U-20836.

1	<u>r urp</u>	<u>ose or resumony</u>			
2	Q7.	What is the purpose of your testimony?			
3	A7.	As referenced in Witness Robinson's description of the distribution witnesses, my			
4		testimony supports, as reasonable and necessary, Distribution Operations' Global			
5		Prioritization Model (GPM), Infrastructure Investment and Jobs Act (IIJA) funding			
6		grants, and updates on the distribution approach to Environmental Justice (EJ).			
7					
8	Q8.	How is your testimony organized?			
9	A8.	My testimony consists of three parts:			
10		Part I Global Prioritization Model			
11		Part II IIJA Grant Opportunities			
12		Part III Environmental Justice			
13					
14	Part ]	I: Global Prioritization Model			
15	Q9.	What is the Global Prioritization Model and what is it used for?			
16	A9.	The GPM is a tool the Company's Distribution Operations team developed to			
17		prioritize investments by ranking projects and programs. The ranking is			
18		accomplished through a process of evaluating and weighting impact dimensions			
19		(project benefits) for each project and program. The model results serve as the			
20		initial basis for the Company's investment plan and highlight those projects that			
21		have the highest benefit to cost ratios.			
22					
23	Q10.	How does the GPM consider DTE Electric's planning objectives when			
24		evaluating the Company's distribution investment options?			

Line

<u>No.</u>

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1	A10.	The Company uses the GPM to assess the impacts strategic investments have on
2		the distribution system in each of three planning objectives of safe, reliable and
3		resilient, and affordable. All impact dimensions that are measured in the GPM are
4		aligned to one of these three planning objectives. These three objectives also align
5		with the Commission's overarching objectives for the electric distribution system,
6		which are safety, reliability and resilience, cost effectiveness and affordability, and
7		accessibility. <sup>1</sup> As set forth in the Company's 2021 Distribution Grid Plan (DGP),
8		DTE Electric has added two planning objectives - "clean" and "customer
9		accessibility and community focus." DTE Electric intends to consider potential
10		updates to the GPM to incorporate these additional planning objectives as part of
11		the process to develop its next DGP.
12		
13	Q11.	What impact dimensions are measured to assess project and program impact
14		across the Company's Planning Objectives and how are projects ranked?
15	A11.	In the GPM, strategic investments are evaluated against seven impact dimensions
16		as described in Table 1. Quantitative assessments are conducted for all the impact
17		dimensions to score and rank investments.
18		

<sup>&</sup>lt;sup>1</sup> See Commission's Order on October 11, 2017 in docket U-18014 (pp10-12) and re-affirmed in the Commission Order on August 20, 2020 in docket U-21047 (pp 36-38).

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<u>No.</u>

2

	Impact Dimension	Major Drivers
	Safety	<ul> <li>Reduction in wire down events</li> <li>Reduction in secondary network cable manhole events</li> <li>Reduction in major substation events</li> </ul>
Safe	Load Relief	<ul><li>System capability to meet area load growth and system operability needs</li><li>Elimination of system overload or over firm</li></ul>
	Regulatory Compliance	<ul> <li>MPSC staff's recommendation (March 30, <u>2010</u> report) on utilities' pole inspection program</li> <li>Docket U-12270 – Service restoration under normal conditions within 8 hours</li> <li>Docket U-12270 – Service restoration under catastrophic conditions within 60 hours</li> <li>Docket U-12270 – Service restoration under all conditions within 36 hours</li> <li>Docket U-12270 – Same circuit repetitive interruption of fewer than five within a 12-month period</li> </ul>
	Major Event Risk	<ul> <li>Reduction in extensive substation outage events that lead to a large amount of stranded load for more than 24 hours</li> </ul>
Reliable & Resilient	Reliability	<ul> <li>Reduction in number of outage events experienced by customers</li> <li>Reduction in restoration duration for outage events</li> </ul>
Affordable	O&M Cost Avoidance	<ul><li>Trouble event reduction and truck roll reduction</li><li>Preventive maintenance spend reduction</li></ul>
	Reactive Capital Avoidance	<ul><li>Trouble event reduction and truck roll reduction</li><li>Reduction in capital replacement during equipment failures</li></ul>

**GPM Impact Dimensions** 

Table 1

#### 3

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5

- Strategic investments are assessed, scored, and ranked in a quantitative manner on how they support/improve each impact dimension. **Table 2** shows the benefit mapping of the investments to each of the impact dimensions.
- 7

-		
-	-	

Program	Safety	Load Relief	Regulatory Compliance	Substation Outage Risk	Reliability	O&M Cost	Reactive Capital
Tree Trimming to the Enhanced Specification	x		х		х	x	х
4.8/8.3 kV Conversion and Consolidation	x	х		х	х	x	х
Substation Risk	х	Х		х	х		х
Load Relief		Х		Х			
System Cable Replacement	х			х	х		x
Breaker Replacement	х			х	х	х	х
ADMS	Х			Х	Х	Х	Х
4.8kV Circuit Automation	х				х	х	
Automation: Substation				х	х	х	х
Subtransmission Hardening	х	х		х	х	х	х
4.8 kV System Hardening	х				х	х	х
Frequent Outage (CEMI)	х		х		х	х	Х
URD Cable Replacement	х				х	х	х
Pole/PTMM	Х		Х		Х	Х	х

#### Table 2 Selected programs and project benefit mapping

2

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4 5 Detailed analyses based on historical data, engineering assessments, and field feedback were used to quantify each investment's benefits within each impact dimension. The quantified benefits were then compared to the investment's costs to derive benefit-cost ratios.

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Unit measurements used for benefit-cost analysis are different for each impact dimension. For example, reliability benefits are captured in customer minutes of

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interruption reduction and O&M and reactive capital benefits are captured in dollars avoided.

Each program's benefit-cost score for each impact dimension is indexed to a base range of 0-100. Projects scoring exceptionally high, above the 95<sup>th</sup> percentile, will receive a score above 100. Indexing is used because not all benefits are easily translated to common unit of measurement (e.g., dollars, SAIDI minutes) and the indexing allows for consideration of both monetary and non-monetary benefits in a single analysis.

10

11 Impact dimensions are weighted against each other. Table 3 lists the different 12 weights given to each impact dimension that reflects our customer priorities. As an 13 example, safety, the Company's most important impact dimension, is weighted 14 more highly than any other dimension. This effectively means that a score of 100 15 in another dimension will not be worth as much as a 100 rating in safety. For 16 example, if a project's safety score is 50 (on a 0-100 scale), it will be multiplied by 17 safety's weighting factor of 10 to receive a score of 500. A project with a reliability 18 score of 100 will be multiplied by the reliability weighting of 3 and contribute 300 19 to the total scoring. This illustrates how the impact dimension weights will rank 20 projects higher if they provide benefits in dimensions which have higher 21 weightings, such as safety. Once a program's index scores have been calculated 22 across all impact dimensions and adjusted by weighting, the index scores are 23 summed together to determine the program's overall benefit-cost score.

#### Line <u>No.</u>

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Impact Dimension	Safety	Load Relief	Regulatory Compliance	Substation Outage Risk	Reliability	O&M Cost	Reactive Capital
Weight	10	4	4	4	3	3	3

#### Table 3Impact Dimension Weights

3	Q12.	How do the GPM results influence the Company's distribution investment
4		decisions?
5	A12.	Projects and programs are ranked using the GPM on an annual basis. Investments
6		that score highest in the GPM rankings are selected for the Company's distribution
7		infrastructure strategic investment plan. Projects and programs that span multiple
8		years are evaluated every year and may experience a change in GPM ranking if
9		additional information changes the expected project costs or benefits.
10		
11	Q13.	What are the benefit-cost scores for the projects and programs proposed in
12		this instant ago?
		this instant case?
13	A13.	The benefit-cost scores for strategic capital programs, ranked from highest to
13 14	A13.	The benefit-cost scores for strategic capital programs, ranked from highest to lowest, are illustrated in Figure 1 and Table 4. Tree trimming <sup>2</sup> to the enhanced
13 14 15	A13.	The benefit-cost scores for strategic capital programs, ranked from highest to lowest, are illustrated in Figure 1 and Table 4. Tree trimming <sup>2</sup> to the enhanced specification, although excluded from the Tables, continues to provide high
13 14 15 16	A13.	The benefit-cost scores for strategic capital programs, ranked from highest to lowest, are illustrated in <b>Figure 1</b> and <b>Table 4</b> . Tree trimming <sup>2</sup> to the enhanced specification, although excluded from the Tables, continues to provide high customer benefits and ranks within the top five projects and programs in the
13 14 15 16 17	A13.	The benefit-cost scores for strategic capital programs, ranked from highest to lowest, are illustrated in <b>Figure 1</b> and <b>Table 4</b> . Tree trimming <sup>2</sup> to the enhanced specification, although excluded from the Tables, continues to provide high customer benefits and ranks within the top five projects and programs in the Company's five-year investment portfolio.

<sup>&</sup>lt;sup>2</sup> Tree trimming, as an O&M program, is excluded from the Figures. Nonetheless, tree trimming to the enhanced specification has a top 5 benefit-cost ranking among all programs.



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#### Table 4 Top 50 Strategic Capital Programs and Projects Based on

GPM

Rank	k Capital Program/ Project		Capital Program / Project
1	ADMS: DMS/OMS	26	Subtransmission Redesign & Rebuild: Pigeon Area Improvement
2	4.8 kV Circuit Automation	27	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion
3	4.8 kV Hardening	28	Cable Replacement Program
4	CODI: Charlotte Network Upgrade	29	Subtransmission Redesign & Rebuild: Trunk 3508
5	Subtransmission Redesign & Rebuild: Thumb Electric Fault Isolation	30	Subtransmission Redesign & Rebuild: Tie 810
6	Automation: Substation	31	System Loading: Richmond/Armada
7	4.8 kV CC: Buckler Circuit Conversion	32	Subtransmission Redesign & Rebuild: Trunk 3509
8	4.8kV CC: Barber Substation and Circuit Conversion	33	Substation Risk: Apache
9	4.8 kV CC: Hawthorne Relief and Circuit Conversion	34	System Loading: Otsego/Capac/Shaw
10	4.8 kV CC: Almont Relief and Circuit Conversion (Midas)	35	System Loading: Macomb/Golf
11	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion	36	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition
12	Automation: 13.2kV Circuit Distribution	37	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker
13	4.8 kV CC: ISO Conversion Program	38	4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)
14	Subtransmission Redesign & Rebuild: Boyne	39	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)
15	CODI: Garfield Network Upgrade	40	CODI: Islandview Substation
16	Subtransmission Redesign & Rebuild: Trunk 4217	41	Subtransmission Redesign & Rebuild: Tie 6602
17	Pole and Pole Top Hardware (PTMM)	42	CODI: Kent/Gibson Conversion
18	4.8 kV CC: Belleville Substation and Circuit Conversion	43	Subtransmission Redesign & Rebuild: Trunk 4266
19	URD Replacement Program	44	CODI: Howard Conversion
20	System Loading: Brown City	45	8.3 kV CC: Pontiac Overhead Conversion
21	Breaker Replacement Program	46	System Loading: Grenada
22	Substation Risk: Chestnut	47	System Loading: Wixom
23	Frequent Outage Program (CEMI)	48	Subtransmission Redesign & Rebuild: Trunk 2308
24	4.8kV CC: Hemlock Decommissioning and Circuit Conversion	49	System Loading: Jewell
25	Subtransmission Redesign & Rebuild: Tie 7504	50	Subtransmission Redesign & Rebuild: Derby

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### Q14. Are there other factors besides the GPM ranking that determine final timing

of program and project selection?

A14. Yes. While the benefit-cost scores of programs and projects and their prioritization
 ranking provide the foundation for the Company's strategic investment decisions,
 there are other considerations that impact capital allocation and project timing, as
 listed below:

6 Funding decisions for programs and projects considers the impact on • 7 workforce needs. Resources required for engineering, design, project 8 management, scheduling, and construction need to be evaluated not only by 9 project type (substation, overhead or underground) but also by geographic 10 location. Resource gaps and balancing are evaluated before funding 11 decisions are made. Funding decisions also consider the Company's capacity 12 to perform the work, as the Company often partners with third parties to plan and execute projects. 13

# System operational constraints and stability, occasionally including transmission, can cause the Company to pull ahead a project. For example, a project may be needed to address subtransmission system integrity caused by load growth.

- Regulatory requirements or guidance also influence the selection of some projects and programs regardless of the GPM ranking. NERC requirements,
   for example, require upgrades to ensure the bulk electric system is unaffected by subtransmission outages. These NERC driven projects have benefits that are difficult to quantify in GPM.
- Significant safety issues that cannot be easily quantified and indexed could
   warrant an investment outside of the GPM model to protect our customers

1		or employees. For instance, subtransmission disconnect switches and
2		Pontiac vault projects are necessary to meet operational safety needs.
3	•	Pilot Projects are excluded from the ranking process as they are used to
4		determine what the true benefits and cost will be to complete an activity that
5		the Company believes will be beneficial to its customers, in other words the
6		pilots help provide the data for future project benefits. An example is non-
7		wire alternative (NWA) projects. These NWA pilot projects focus on using
8		alternative technologies to address circuit or substation overload concerns to
9		help delay or offset traditional grid upgrades. The Company developed these
10		NWA pilots to better understand the customer and costs benefits as part of
11		the longer-term grid modernization plan, so that in the future these can be
12		evaluated against more traditional alternatives. These pilots are supported by
13		Company witness Hill and detail is provided in Exhibit A-12 Schedule
14		B5.4.1 through B5.4.7.
15	•	Capital projects are subject to development milestones, especially in the
16		conceptual design and early development stages, including land availability
17		and property purchases, municipal approvals and construction permits, right-
18		of-way acquisition and easements, and lead times when procuring major
19		equipment. While the Company takes proactive measures to mitigate these
20		execution risks, many of these early-stage milestones are difficult for the
21		Company to control and can introduce schedule delays or cost increases.
22		Therefore, the Company's investment and maintenance plan is designed to
23		include some flexibility to accommodate these unpredictable variations in
24		timing and cost.

<u>No.</u>		
1		• Some capital replacement programs are funded annually, to avoid
2		acceleration of asset failures and the risk that a large quantity of assets would
3		reach end-of-life concurrently, thus exceeding available resources to replace
4		them (e.g., underground residential distribution cable program).
5		• If the Company is awarded grant money from the state or federal government
6		for specific projects, including IIJA grants, it could positively impact project
7		selection due to grant project completion requirements.
8		
9		It is important to note that some programs and projects may not receive funding in
10		a particular year due to lower benefit-cost scores, but this does not indicate that
11		these programs or projects are not beneficial to customers, or that they may not be
12		selected in other years. Rather, all the programs and projects identified by the
13		Company provide system improvements and may be funded at some point over the
14		next several years. While the strategic capital investment plan is primarily driven
15		by the GPM, the Company may adjust the annual plans based on changing
16		circumstances.
17		
18	Q15.	Do the GPM scores and rankings have the potential to change over time?
19	A15.	Yes. As the Company continues to make investments in distribution infrastructure,
20		the effectiveness of the capital spend is examined on a regular basis. The benefit-
21		cost scores of the programs and projects may change over time as new data becomes
22		available. The prioritization ranking of the programs and projects may change
23		accordingly.

Line

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#### 1 Part II: IIJA Grant Opportunities 2 Q16. What are IIJA grants? 3 In November 2021, the IIJA was signed into federal law, providing funding A16. 4 opportunities focused on many topics, including grid reliability and resilience and 5 other infrastructure investments. 6 7 Q17. Does the Company intend to seek any grant funding to invest in the 8 distribution system through the IIJA process? 9 A17. Yes, currently, the Company intends to pursue three grants through the US 10 Department of Energy (DOE) as part of the IIJA implementation and is working 11 with the State of Michigan on a fourth grant opportunity. Grants can be beneficial 12 because the Company can leverage Federal and State dollars to upgrade the 13 distribution grid without having to fund a portion of the projects through customer 14 rates. The three grants the Company is actively pursuing are Section 40101(c) -15 Grid Resilience, Section 40107 – Smart Grid, and Section 40101(d) – Preventing 16 Outages and Enhancing the Resilience of the Electric Grid. The fourth grant 17 opportunity that is still in development, led by the State of Michigan, is for Section 18 40103(b) – Grid Innovation Program. 19

#### 20 Q18. What are the objectives and details of the 40101(c) Grid Resilience grant?

A18. The objective of this grant is to support activities that will modernize the electric grid to reduce impacts due to extreme weather and natural disasters. The Department of Energy (DOE) intends to award up to seven grants to large utilities throughout the entire country with awards of up to \$100 million. The eligible entities for this grant are electric grid operators, electricity generators, electricity

Line No.

> 1 storage operators, transmission owners or operators, distribution providers, and fuel 2 suppliers. The investments must occur within 60 months of the award. The first step 3 towards being awarded a grant is to file a concept paper for the project and receive 4 encouragement from the DOE to proceed with a formal grant application. DTE 5 Electric filed a concept paper on December 16, 2022 and intends to submit a full application by April 6, 2023, if encouraged to do so by the DOE. Awards will be 6 7 announced approximately two months after applications are due. Due to the limited 8 number of grants available and number of eligible entities, the grant process is 9 expected to be highly competitive.

10

#### 11 Q19. What are the objectives and details of the 40107 Smart Grid grant?

12 A19. The objective of this grant is to increase the flexibility, efficiency, and reliability of 13 the electric power system, with particular focus on increasing capacity of the transmission system, preventing faults or other system disturbances, integrating 14 15 renewables at the transmission and distribution levels, and facilitating the 16 integration of increasing electrified vehicles, buildings, and other grid edge devices. 17 The DOE intends to award up to 25-40 grants with individual awards of up to \$50 18 million. The eligible entities for this grant are any for-profit entity, institutes of 19 higher education, non-profit entities, states, local governments, and tribes. The 20 investments must occur within 60 months of the award. DTE Electric filed a 21 concept paper on December 16, 2022 and intends to submit a full application by 22 March 17, 2023, if encouraged to do so by the DOE. Due to the broad number of 23 entities eligible to apply for this funding, the grant process is expected to be highly 24 competitive.

## Q20. What are the objectives and details of the 40101(d) Preventing Outages and Enhancing the Resilience of the Electric Grid grant?

3 A20. Unlike the two grants described above (40101c and 40107), this grant is an indirect 4 grant for which the Company cannot directly apply. Instead, the Michigan 5 Department of Environment Great Lakes, and Energy (EGLE) will apply for DOE 6 funding with the support of the MPSC. The objectives of this grant are similar to 7 the 40101(c) grant with a focus on improving energy resilience and investing in 8 modernized grid infrastructure. EGLE held a public hearing on its plans for this 9 grant opportunity on November 10, 2022, where it described the opportunity and 10 timing for funding. Overall, EGLE intends to award approximately \$4 million in 11 funding between the two largest utilities in the state of Michigan (DTE Electric and 12 Consumers Energy). These funds would apply to projects or programs to be 13 implemented starting in September 2023. The DOE approval of the EGLE 14 application is expected to occur in February 2023, and DTE Electric intends to 15 submit project proposals to EGLE and the MPSC in March or April of 2023. Similar 16 to the other grants, a 1:1 match of funds is required from DTE Electric for any 17 project.

18

#### 19 Q21. What are the objectives and details of the 40103(b) Grid Innovation grant?

A21. Similar to 40101(d), this grant is an indirect grant for which the Company cannot
 directly apply. Rather, EGLE is eligible to apply for DOE funding with the support
 of the MPSC. Eligible direct applicants include States, Indian Tribes, local
 governments, and public utility commissions. The objectives for this grant are to
 demonstrate innovative approaches to transmission, distribution, and storage to
 harden and enhance resilience and reliability; and demonstrate new approaches to

1	enhance regional grid resilience implemented through States by public and rural
2	electric cooperative entities on a cost-shared basis. The cost share is 50% whereby
3	applicants would be expected to match 1:1 of the federal grant dollars (e.g.,
4	\$500,000 total project cost with half from DOE and half from the applicant). For
5	this grant, DOE estimates up to \$250 million award size and awarding 4-40
6	applications. DTE Electric looks forward to supporting a direct applicant (e.g.,
7	State, PUC, local government) in this process. Following the concept paper process,
8	applications are due on May 19, 2023.

## Q22. Is the Company requesting funding in this rate case for investments or expenses that may be covered by any of the grants discussed above?

- 12 No, with one exception. The Company is requesting \$0.8M in this rate case for A22. 13 initial engineering and design work in 2024 for a project that would fall under the 14 40101(c) grant. DTE Electric has included this engineering and design work in this 15 rate case request because it will be pursuing some part of this project with or 16 without the grant funding. If the 40101(c) grant is awarded to DTE Electric, it 17 would enable the Company to more quickly implement the project with the support 18 of the federal funds. The funding timeline for the 40101(c) grant is 60 months from 19 the award of the grant, and a majority of the investments for this project would take 20 place in 2025-2028; thus, proposed investment levels associated with this grant, 21 including the Company's match for the grant, would be addressed in future rate 22 cases. The other two grants that are being actively pursued do not have funding 23 requests in this rate case, meaning the grant-funded work would be incremental to 24 the proposed investments set forth in this rate case.
- 25

#### 1 **Q23.** If the Company is successful at obtaining any of the grants discussed above, 2 what will the Company's financial obligation be? 3 A23. For the three grants the Company is actively pursuing, a 1:1 funding match of 4 federal funds will be required. For example, in the 40101(c) grant application, if 5 DOE awards \$100 million of funding, DTE would need to contribute a minimum 6 of \$100 million in matching funds. DTE Electric customers would receive system 7 improvements through the federal grants without having to pay for the full amount 8 of the project(s) through electric rates. Because this rate case does not include any 9 amounts for DTE Electric's match, it is expected that the cost recovery for the 10 Company's match amounts would be requested in future rate cases. 11 12 Q24. What happens if the grant requires that the Company provide matching 13 funding for a grant project before it can be presented for approval in a future 14 rate case? 15 A24. The Company will notify the Commission through the ongoing docket on IIJA 16 grants (U-21227) and discuss needed adjustments to the capital plan and funding 17 allocations. While the DOE has shared some timelines, the timing of grant awards 18 and associated work performed is still uncertain at this time. 19 20 Part III: Environmental Justice 21 How does the Company evaluate environmental justice? **O25**. 22 A25. The Company has evaluated it in the context of the State of Michigan's definition 23 of environmental justice (EJ). The State of Michigan defines EJ as, "the equitable 24 treatment and meaningful involvement of all people, regardless of race, color, 25 national origin, ability, or income in the development and application of laws,

Line <u>No.</u>		U-21297
1		regulations, and policies that affect the environment, as well as the places people
2		live, work, play, worship, and learn." <sup>3</sup>
3		
4	Q26.	How did DTE Electric address EJ in its 2021 DGP filing?
5	A26.	The 2021 DGP discussed EJ in the context of distribution planning and operations.
6		The DGP identifies an approach to address service reliability in vulnerable
7		communities, to assess the Company's GPM for prioritizing investment projects to
8		determine how to better account for equity to support vulnerable communities, and
9		to optimize distribution operations. The Company also identified at the time of the
10		DGP filing, that the basis and source of data defining vulnerable communities
11		would be the MiEJ Screen tool, which at the time of the 2021 DGP filing was not
12		yet available.
13		
14	Q27.	Has the State of Michigan now published a tool providing environmental
15		justice data and the identification of vulnerable communities, since the 2021
16		DGP and the Company's last rate case filing (Case No. U-20836)?
17	A27.	Yes. EGLE released the draft version of the MiEJScreen tool in March of 2022
18		following a public comment process. <sup>4</sup> This tool combines environmental conditions
19		and population characteristics to highlight, by census tract, where the most
20		vulnerable communities in Michigan are located. EGLE does not explicitly define
21		the threshold for which communities are vulnerable and which ones are not
22		vulnerable. A final MiEJScreen tool has not been released.
23		

<sup>3</sup> State of Michigan, Department of Environment, Great Lakes, and Energy, https://www.michigan.gov/egle/public/learn/environmental-justice, accessed January 18, 2023.
 <sup>4</sup> <u>MiEJScreen: Environmental Justice Screening Tool (DRAFT) (michigan.gov)</u>

#### 1 Q28. How did DTE Electric Distribution Operations define a vulnerable community 2 for use with the draft MiEJScreen Tool? 3 A28. The DTE Electric Distribution Operations organization chose to adopt an 80% 4 threshold definition for vulnerable communities using the draft MiEJScreen Tool score, consistent with the U.S. EPA approach<sup>5</sup>. Following this approach, census 5 tracts with a MIEJScreen composite score at or above the 80<sup>th</sup> percentile are 6 7 considered vulnerable communities for the purpose of this testimony and associated 8 analysis. The draft MiEJScreen composite score is calculated using categories and 9 indicators for environmental and population data as shown in Figure 2 below. The 10 Commission recently directed its Energy Affordability and Accessibility 11 Collaborative to address definitions of terms such as environmental justice, grid

12 equity, and energy justice (Case No. U-20836, pp 462-463).

<sup>&</sup>lt;sup>5</sup> 80th percentile, EPA, https://www.epa.gov/ejscreen/frequent-questions-about-ejscreen#q5, accessed January 11, 2023.



3	Q29.	In its 2021 DGP, DTE Electric discussed conducting analysis of electric
4		reliability data using the draft MiEJScreen Tool when available. With the tool
5		now available in draft form, is the Company able to group reliability statistics
6		by geographic area (i.e., census tracts and zip codes) to begin that analysis?
7	A29.	Yes. DTE Electric tracks reliability statistics by customer, which are then rolled up
8		to a circuit and substation. However, circuits often cross more than one census tract
9		or zip code. DTE Electric is actively working to match residential meters to census
10		tracts defined by the U.S. Census. Commercial properties are not surveyed as part
11		of the U.S. Census, and therefore, their addresses and associated meters are not
12		assigned to a census tract for the purposes of this analysis. There are other meters,
13		due to ongoing data cleaning work, that have yet to be placed in a census tract/zip

Figure 2 MiEJScreen Overall Score Calculation

1		code. Currently, most meters have been successfully mapped to zip code and census
2		tract, and the Company has confidence that the reliability performance tracked by
3		zip code and census tract is reasonably accurate. There are some small census tracts
4		with a small number of customers where reliability statistics may be abnormally
5		high or low due to small sample size.
6		
7	Q30.	Will the Company provide reliability statistics by census tracts to the
8		Commission?
9	A30.	Yes, the Company has made progress in accordance with the Commission's
10		expectations, specified in its March 3,2022 Order in Case No. U-21122, to provide
11		data by census tract for the purpose of evaluating its performance in providing
12		service to vulnerable communities. The Commission's March 3, 2022, order in
13		Case No. U-21122 directed its Staff to work with utilities and stakeholders to
14		develop a template by November 18, 2022 for utility reporting of reliability, outage,
15		and storm response data. The Commission Staff filed the template in the docket on
16		November 18, 2022. The Company understands that the Commission plans to begin
17		collecting the specified reliability data starting with the first quarter of 2023.
18		
19	Q31.	Using available data, is the Company able to provide a geographic
20		representation of 2022 electric reliability data by census tracts?
21	A31.	Yes. Using the meters that are matched to census tracts, DTE Electric developed
22		reliability data for SAIDI and SAIFI by census tract and grouped the data into DTE
23		Electric reliability quartiles, with first quartile customers (shown below in green)
24		experiencing the best reliability and fourth quartile customers (shown below in red)
25		experiencing the worst reliability. Looking specifically at outage frequency, first

Line	
No.	

10	Figure 5, and Figure 6.
9	Maps for SAIFI and SAIDI by census tract are included in Figure 3, Figure 4,
8	quartile customers have experienced outage duration in excess of 815 minutes.
7	third quartile customers are between 320 minutes and 815 minutes, and fourth
6	than 113 minutes, second quartile customers range between 113 and 320 minutes,
5	duration, first quartile reliability customers have a 2022 SAIDI performance less
4	customers have performance in excess of 1.75 interruptions. Looking at outage
3	third quartile customers are between 1.08 and 1.75 interruptions, and fourth quartile
2	interruptions, second quartile customers range between 0.59 and 1.08 interruptions,
1	quartile reliability customers have a 2022 SAIFI performance fewer than 0.59



Reliability quartiles based on DTE internal metrics for 2022

0 5 10 20 Miles

3

Line



Line



#### Figure 5 – 2022 All Weather SAIDI by Census Tract for DTE Electric



1

(Full Electric Service Area)





Line

3 Q32. Are all census tracts equal in geographic size and population?

1	A32.	No. Census tracts vary in geographic size and population. According to the U.S.
2		Census Bureau, census tracts generally have a population size between 1,200 and
3		8,000 people, with an optimum size of 4,000 people. <sup>6</sup> In addition, the geographical
4		size of the tract does not represent how many people are in it. In some areas there
5		are large tracts (both first and fourth quartile) that have fewer customers in them,
6		compared to much smaller sized tracts in more dense urban areas. When the
7		reliability data is looked at in a map, as shown above, the lightly populated,
8		geographically large census tracts can visually skew the underlying reliability data.
9		
10	Q33.	How does the reliability performance of census tracts in vulnerable
11		communities (identified as at or above the 80 <sup>th</sup> percentile in the draft
11 12		communities (identified as at or above the 80 <sup>th</sup> percentile in the draft MiEJScreen Tool) compare with the rest of the DTE Electric system?
11 12 13	A33.	communities (identified as at or above the 80 <sup>th</sup> percentile in the draft MiEJScreen Tool) compare with the rest of the DTE Electric system? The results vary significantly from census tract to census tract. In the DTE Electric
11 12 13 14	A33.	communities (identified as at or above the 80 <sup>th</sup> percentile in the draft MiEJScreen Tool) compare with the rest of the DTE Electric system? The results vary significantly from census tract to census tract. In the DTE Electric service territory, there are 483 census tracts that fall into the range of having a
<ol> <li>11</li> <li>12</li> <li>13</li> <li>14</li> <li>15</li> </ol>	A33.	communities (identified as at or above the 80 <sup>th</sup> percentile in the draft MiEJScreen Tool) compare with the rest of the DTE Electric system? The results vary significantly from census tract to census tract. In the DTE Electric service territory, there are 483 census tracts that fall into the range of having a composite draft MiEJScreen score at or above 80 <sup>th</sup> percentile. These 483 census
<ol> <li>11</li> <li>12</li> <li>13</li> <li>14</li> <li>15</li> <li>16</li> </ol>	A33.	communities (identified as at or above the 80 <sup>th</sup> percentile in the draft MiEJScreen Tool) compare with the rest of the DTE Electric system? The results vary significantly from census tract to census tract. In the DTE Electric service territory, there are 483 census tracts that fall into the range of having a composite draft MiEJScreen score at or above 80 <sup>th</sup> percentile. These 483 census tracts represent 29% of the total census tracts in DTE Electric's service area and
<ol> <li>11</li> <li>12</li> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> </ol>	A33.	communities (identified as at or above the 80 <sup>th</sup> percentile in the draft MiEJScreen Tool) compare with the rest of the DTE Electric system? The results vary significantly from census tract to census tract. In the DTE Electric service territory, there are 483 census tracts that fall into the range of having a composite draft MiEJScreen score at or above 80 <sup>th</sup> percentile. These 483 census tracts represent 29% of the total census tracts in DTE Electric's service area and account for approximately 550,000 residential customers. <sup>7</sup> Additionally, these
<ol> <li>11</li> <li>12</li> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> </ol>	A33.	communities (identified as at or above the 80 <sup>th</sup> percentile in the draft MiEJScreen Tool) compare with the rest of the DTE Electric system? The results vary significantly from census tract to census tract. In the DTE Electric service territory, there are 483 census tracts that fall into the range of having a composite draft MiEJScreen score at or above 80 <sup>th</sup> percentile. These 483 census tracts represent 29% of the total census tracts in DTE Electric's service area and account for approximately 550,000 residential customers. <sup>7</sup> Additionally, these tracts include a total of 1,032 circuits out of DTE Electric's 3,222 distribution
<ol> <li>11</li> <li>12</li> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> </ol>	A33.	communities (identified as at or above the 80 <sup>th</sup> percentile in the draft MiEJScreen Tool) compare with the rest of the DTE Electric system? The results vary significantly from census tract to census tract. In the DTE Electric service territory, there are 483 census tracts that fall into the range of having a composite draft MiEJScreen score at or above 80 <sup>th</sup> percentile. These 483 census tracts represent 29% of the total census tracts in DTE Electric's service area and account for approximately 550,000 residential customers. <sup>7</sup> Additionally, these tracts include a total of 1,032 circuits out of DTE Electric's 3,222 distribution circuits <sup>8</sup> (32% of total circuits) and contain 8,289 circuit miles compared to 44,320
<ol> <li>11</li> <li>12</li> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> </ol>	A33.	communities (identified as at or above the 80 <sup>th</sup> percentile in the draft MiEJScreen Tool) compare with the rest of the DTE Electric system? The results vary significantly from census tract to census tract. In the DTE Electric service territory, there are 483 census tracts that fall into the range of having a composite draft MiEJScreen score at or above 80 <sup>th</sup> percentile. These 483 census tracts represent 29% of the total census tracts in DTE Electric's service area and account for approximately 550,000 residential customers. <sup>7</sup> Additionally, these tracts include a total of 1,032 circuits out of DTE Electric's 3,222 distribution circuits <sup>8</sup> (32% of total circuits) and contain 8,289 circuit miles compared to 44,320 total distribution circuit miles <sup>9</sup> (19% of total distribution miles).

<sup>&</sup>lt;sup>6</sup> US Census Bureau, Glossary, available at <u>Glossary (census.gov)</u>, accessed January 14, 2023.
<sup>7</sup> There are a total of 1,643 census tracts in DTE Electric's service territory.
<sup>8</sup> Total circuits are discussed in Witness Robinson's testimony
<sup>9</sup> Total circuits miles are discussed in Witness Robinson's testimony

Line <u>No.</u>

1	These 483 census tracts have a range of SAIDI <sup>10</sup> and SAIFI <sup>11</sup> reliability
2	performance that spans from first quartile performance to fourth quartile
3	performance. When compared to the remainder of the service territory, these 483
4	census tracts collectively have above average reliability performance in years 2020
5	through 2022, for SAIDI and SAIFI metrics excluding MEDs and All-Weather
6	SAIFI compared to the systemwide levels, with exception. Please refer to Table 5
7	for reliability performance. See Figure 7, Figure 8, Figure 9, and Figure 10 for
8	maps with systemwide 2022 reliability quartiles for vulnerable census tracts within
9	DTE Electric's service territory.

 <sup>&</sup>lt;sup>10</sup> System Average Interruption Duration Index – calculated by dividing total number of customer outage minutes by total number of customers
 <sup>11</sup> System Average Interruption Frequency Index – calculated by dividing total number of customer

interruptions by total number of customers

#### Table 5 Reliability Performance of Vulnerable Census Tracts (MiEJ)

#### score of 80% to 100%) Versus System Average

	2020	2021	2022
All weather SAIFI vulnerable communities	1.08	1.32	1.13
All weather SAIFI system average	1.29	1.58	1.25
Non-MED SAIFI vulnerable communities	0.83	0.76	0.81
Non-MED SAIFI system average	1.01	0.92	0.98
All weather SAIDI vulnerable communities	361	842	737
All weather SAIDI system average	352	927	584
Non-MED SAIDI vulnerable communities	136	117	131
Non-MED SAIDI system average	142	136	146

Over performing system average

Under performing system average

System average

Line <u>No.</u>

1



#### Figure 7 - 2022 All Weather SAIFI for Vulnerable Census Tracts with

MiEJ Score of 80% to 100%



Line <u>No.</u>

rosse te Farms



War

troit

LaSall

Windsor

Quartile

0

SAIFI Q1 <= 0.59

Q4 >1.76

4

2

Q2 0.59 to <= 1.08

Q3 1.08 to <= 1.76

8 Miles

1

Reliability quartiles based on DTE internal metrics for 2022

Southgate

aylo

Line

aton W 9

anden City

Dearl





Line



Q34. Has the company started to evaluate how its investment programs are
 reaching vulnerable communities to improve electric distribution
 infrastructure and reliability performance?

Line <u>No.</u>

1	A34.	Yes. Historically, the Company has evaluated investments to prioritize safety,
2		reliability and other factors across the Company's service area, emphasizing among
3		other things, at-risk equipment, number of customers affected, and areas with lower
4		reliability performance. In recent years, this prioritization has led to a shift of
5		hardening and tree trim investment in the City of Detroit to address aging
6		infrastructure. To better understand the extent to which the Company's overall
7		investments are reaching vulnerable communities relative to other areas, I
8		examined how some of the Company's largest distribution investment projects and
9		programs addressed areas with a composite draft MiEJScreen score at or above the
10		80 <sup>th</sup> percentile threshold.
11		
12	Q35.	What are the results of the investment analysis regarding vulnerable
12		communities?
15		communities:
13	A35.	The results are summarized in <b>Table 6</b> below and indicate that the Company's
14 15	A35.	The results are summarized in <b>Table 6</b> below and indicate that the Company's investments are supporting vulnerable customers and communities – identified as
14 15 16	A35.	The results are summarized in <b>Table 6</b> below and indicate that the Company's investments are supporting vulnerable customers and communities – identified as at or above the $80^{\text{th}}$ percentile in the draft MiEJScreen Tool – in southeast
13 14 15 16 17	A35.	The results are summarized in <b>Table 6</b> below and indicate that the Company's investments are supporting vulnerable customers and communities – identified as at or above the 80 <sup>th</sup> percentile in the draft MiEJScreen Tool – in southeast Michigan, including the City of Detroit. This analysis is based on the draft
14 15 16 17 18	A35.	The results are summarized in <b>Table 6</b> below and indicate that the Company's investments are supporting vulnerable customers and communities – identified as at or above the 80 <sup>th</sup> percentile in the draft MiEJScreen Tool – in southeast Michigan, including the City of Detroit. This analysis is based on the draft MiEJScreen Tool census tract data and Company investment data on the circuits
14 15 16 17 18 19	A35.	The results are summarized in <b>Table 6</b> below and indicate that the Company's investments are supporting vulnerable customers and communities – identified as at or above the 80 <sup>th</sup> percentile in the draft MiEJScreen Tool – in southeast Michigan, including the City of Detroit. This analysis is based on the draft MiEJScreen Tool census tract data and Company investment data on the circuits addressed by the following three programs over the timeframe 2018-2022: 4.8kV
13 14 15 16 17 18 19 20	A35.	The results are summarized in <b>Table 6</b> below and indicate that the Company's investments are supporting vulnerable customers and communities – identified as at or above the 80 <sup>th</sup> percentile in the draft MiEJScreen Tool – in southeast Michigan, including the City of Detroit. This analysis is based on the draft MiEJScreen Tool census tract data and Company investment data on the circuits addressed by the following three programs over the timeframe 2018-2022: 4.8kV Hardening, Tree Trimming and Conversions. For each of these investment
<ol> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> </ol>	A35.	The results are summarized in <b>Table 6</b> below and indicate that the Company's investments are supporting vulnerable customers and communities – identified as at or above the 80 <sup>th</sup> percentile in the draft MiEJScreen Tool – in southeast Michigan, including the City of Detroit. This analysis is based on the draft MiEJScreen Tool census tract data and Company investment data on the circuits addressed by the following three programs over the timeframe 2018-2022: 4.8kV Hardening, Tree Trimming and Conversions. For each of these investment programs, <b>Table 6</b> below shows the total number of circuits addressed by the
<ol> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> </ol>	A35.	The results are summarized in <b>Table 6</b> below and indicate that the Company's investments are supporting vulnerable customers and communities – identified as at or above the 80 <sup>th</sup> percentile in the draft MiEJScreen Tool – in southeast Michigan, including the City of Detroit. This analysis is based on the draft MiEJScreen Tool census tract data and Company investment data on the circuits addressed by the following three programs over the timeframe 2018-2022: 4.8kV Hardening, Tree Trimming and Conversions. For each of these investment programs, <b>Table 6</b> below shows the total number of circuits addressed by the respective program, the total number of circuits in identified vulnerable
<ol> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>23</li> </ol>	A35.	The results are summarized in <b>Table 6</b> below and indicate that the Company's investments are supporting vulnerable customers and communities – identified as at or above the 80 <sup>th</sup> percentile in the draft MiEJScreen Tool – in southeast Michigan, including the City of Detroit. This analysis is based on the draft MiEJScreen Tool census tract data and Company investment data on the circuits addressed by the following three programs over the timeframe 2018-2022: 4.8kV Hardening, Tree Trimming and Conversions. For each of these investment programs, <b>Table 6</b> below shows the total number of circuits addressed by the respective program, the total number of circuits in identified vulnerable communities addressed by the respective program, and the percentage of the
<ol> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>23</li> <li>24</li> </ol>	A35.	The results are summarized in <b>Table 6</b> below and indicate that the Company's investments are supporting vulnerable customers and communities – identified as at or above the 80 <sup>th</sup> percentile in the draft MiEJScreen Tool – in southeast Michigan, including the City of Detroit. This analysis is based on the draft MiEJScreen Tool census tract data and Company investment data on the circuits addressed by the following three programs over the timeframe 2018-2022: 4.8kV Hardening, Tree Trimming and Conversions. For each of these investment programs, <b>Table 6</b> below shows the total number of circuits addressed by the respective program, the total number of circuits in identified vulnerable communities addressed by the program that are in vulnerable communities. Additionally,
1

vulnerable communities, and percentage of program investment in vulnerable 2 communities. For example, 83% of the work performed under the hardening 3 program occurred in vulnerable communities. As discussed by Witness Elliott 4 Andahazy, the hardening program has resulted in documented reliability and safety 5 improvements, including reduction in the frequency and duration of outages and 6 fewer downed wires, through the program's clearing of right of way, equipment 7 upgrades, and removal of arc wire.

8

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Table 6	2018 to 2022 Investment in Vulnerable Communities (Census
	Tracts with MiEJ Score of 80% to 100%)

Investment Program (2018-2022)	Total Investment by Program (M)	Total Investment by Program in Vulnerable Census Tracts (M)	% Of Investment in Vulnerable Census Tracts	Total Number of Circuits Addressed by Program	Number of Circuits Addressed by Program in Vulnerable Census Tracts	% Of Program Circuits in Vulnerable Census Tracts
Conversion	\$ 234	\$ 176	75%	694	318	46%
4.8kV Hardening	\$ 290	\$ 270	93%	183	151	83%
Tree Trim	\$ 785	\$ 236	30%	2416	773	32%

12

13 Q36. How will these distribution investment programs address vulnerable 14 communities in 2023-2024 based on the Company's planned execution of 15 investments in the instant case?

9

10

11

12

1	A36.	Witness Deol, Witness Elliott Andahazy, and Witness Hartwick address the
2		Company's planned investments for 2023 and 2024 for conversions, hardening, and
3		tree trimming, respectively. While the sequencing of specific investments in
4		specific areas within DTE Electric's service area could change based on several
5		factors, such as local permitting and equipment and labor availability, the Company
6		has plans in place for the deployment of these near-term programs. Based on these
7		plans, Table 7 below estimates how these programs will impact circuits/projects
8		located in areas at or above the 80 <sup>th</sup> percentile threshold.

# Table 72023-2024 Investment in Vulnerable Communities (CensusTracts with MiEJ Score of 80% to 100%)

Investment Program (2023-2024)	Total Investment by Program (M)	Total Investment by Program in Vulnerable Census Tracts (M)	% Of Investment in Vulnerable Census Tracts	Total Number of Circuits Addressed by Program	Number of Circuits Addressed by Program in Vulnerable Census Tracts	% Of Program Circuits in Vulnerable Census Tracts
Conversion	\$ 602	\$ 517	86%	694	318	46%
4.8kV Hardening	\$ 165	\$ 149	90%	125	91	73%
Tree Trim (2023 Only) <sup>12</sup>	\$ 146	\$ 21	14%	609	101	17%

13

# Q37. What are the Company's future plans to address EJ in the context of distribution planning and operations?

<sup>&</sup>lt;sup>12</sup> Tree Trim has not finalized circuits to be trimmed in 2024

<u>No.</u>		
1	A37.	In the context of distribution operations, DTE Electric plans to continue to analyze
2		reliability and investment data using the draft MiEJScreen tool, including the

reliability and investment data using the draft MiEJScreen tool, including the consideration of any updates based on the state's forthcoming release of the tool's final version. In the next Distribution Grid Plan, the company intends to update the GPM in support of EJ considerations in investment decisions. Finally, DTE Electric will collaborate with the MPSC and other stakeholders on potential IIJA grant opportunities to fund infrastructure-related programs to benefit vulnerable communities in alignment with the Biden Administration's Justice40 initiative.<sup>13</sup>

9

Line

#### 10 **Q38.** Does this complete your direct testimony?

11 A38. Yes, it does.

<sup>&</sup>lt;sup>13</sup> The White House, Justice40: A Whole-of-Government Initiative, available at: <u>Justice40 Initiative</u> | <u>Environmental Justice | The White House</u>, accessed January 14, 2023.

## **STATE OF MICHIGAN**

## **BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

In the matter of the Application of	)
DTE ELECTRIC COMPANY	)
for authority to increase its rates, amend	)
its rate schedules and rules governing the	)
distribution and supply of electric energy, and	)
for miscellaneous accounting authority.	)

Case No. U-21297

#### QUALIFICATIONS

#### AND

## DIRECT TESTIMONY

OF

#### ROBERT J. LEE

## DTE ELECTRIC COMPANY QUALIFICATIONS AND DIRECT TESTIMONY OF ROBERT J. LEE

Line <u>No.</u>

1	Q1.	What is your name, business address and by whom are you employed?
2	A1.	My name is Robert J. Lee (he/him/his) and my business address is One Energy
3		Plaza, Detroit, Michigan 48226-1279. I am employed by DTE Energy Corporate
4		Services, LLC within DTE's Environmental Management and Safety team and I
5		am currently the Manager of Environmental Strategy for the Company.
6		
7	Q2.	On whose behalf are you testifying?
8	A2.	I am testifying on behalf of DTE Electric Company (DTE Electric or Company).
9		
10	Q3.	What is your educational background?
11	A3.	I received a Bachelor of Science Degree in Geology in 1992 and a Master of
12		Science Degree in Environmental Geochemistry in 1994 from the University of
13		Wales.
14		
15	Q4.	What is your work experience?
16	A4.	Since completing my formal education, I have practiced continuously in the
17		environmental field with a focus on State and Federal programs mostly in
18		Michigan. My past and current responsibilities include management of several
19		environmental program areas, including Effluent Limitations Guidelines (ELG),
20		Coal Combustion Residual (CCR), remediation program management, State and
21		Federal construction permit programs, and coal plant retirement. Additionally, I
22		have State and Federal level experience supporting and developing legislative and
23		rule-making initiatives.

1 From 1994 to 2004, I worked in the environmental consulting and environmental 2 engineering fields in several different capacities, and in roles with progressively 3 increasing responsibilities. During this time, I was a Project Manager of complex 4 multi-media environmental projects. I managed a wide variety of projects for 5 various industries focusing on remediation project management, solid waste 6 compliance and project management, National Pollutant Discharge Elimination 7 System (NPDES) permit management and obtaining and managing State and 8 Federal permits. I also performed complex multi-site due diligence and liability 9 management. I worked for a variety of industries including utility, cement 10 production, and landfill industry sectors.

11

#### 12 Q5. What are your current duties and responsibilities?

13 A5. I have worked for DTE Energy for 18 years. I am currently the Manager of 14 Environmental Strategy, and my focus is on complex and strategic environmental 15 initiatives that are critical to DTE. In this role I focus on environmental strategy, 16 policy, and regulatory development and am responsible for key environmental 17 programs at the State and Federal level that are critical to the Company's 18 compliance, strategic direction, and generation strategy. I am responsible for the 19 Company's strategy and approach for compliance with the CCR and ELG 20 programs, coal plant retirement, asset reuse, and waste program.

21

# Q6. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

- 24 A6. Yes. I have sponsored testimony in the following cases:
- 25 U-16999 2012 DTE Gas General Rate Case

Line	
<u>No.</u>	

1	U-17999	2015 DTE Gas General Rate Case
2	U-20642	2019 DTE Gas General Rate Case
3	U-20940	2021 DTE Gas General Rate Case
4	U-20836	2022 DTE Electric General Rate Case

1	<u>Purp</u>	ose of Testimony
2	Q7.	What is the purpose of your testimony?
3	A7.	I will describe the status of two significant Environmental Protection Agency
4		(EPA) regulations, the Steam Electric Effluent Limitation Guidelines (ELG) Rule
5		and the Coal Combustion Residuals (CCR) Rule, which impact the Company's
6		coal-fired power plants. I will address the following additional topics in my
7		testimony:
8		1) I will explain the ELG Rule, recent revisions, and compliance strategies in
9		support of Witness Morren's discussion of ELG-related capital
10		expenditures
11		2) I will describe how the EPA's CCR Rule affects the Company's coal-fired
12		units in support of Witness Morren's discussion of CCR-related capital
13		expenditures
14		
15	Q8.	Are you sponsoring any exhibits in this proceeding?
16	A8.	No.
17		
18	Q9.	Is the Company requesting recovery of capital expenditures associated with
19		compliance with EPA regulations?
20	A9.	Yes. As shown in Company Witness Morren's Exhibit A-12, Schedule B5.1, the
21		Company is in the process of developing and implementing several ELG and CCR
22		compliance projects necessitating capital expenditures, including:
23		• Monroe Dry Fly Ash Conversion (ELG)
24		Monroe Bottom Ash Conversion (ELG)
25		• Monroe FGD Wastewater (ELG)

Line <u>No.</u>

Line No		<b>R. J. LEE</b> U-21297
1		• Sibley Quarry Landfill Modification (CCR)
2		• Sibley Quarry Conveyor Installation (CCR)
3		• Sibley Quarry Infrastructure Modification (CCR)
4		• Monroe Bottom Ash Basin Closure (CCR)
5		• River Rouge Bottom Ash Basin Closure (CCR)
6		• St. Clair Bottom Ash Basin Closure (CCR)
7		• Belle River Bottom Ash Basin Modification (CCR)
8		
9	<u>Efflue</u>	ent Limit Guidelines
10	Q10.	What are the Effluent Limit Guidelines (ELGs)?
11	A10.	Effluent Limit Guidelines are national wastewater discharge standards that are
12		developed by EPA on an industry-by-industry basis. These are technology-based
13		regulations and are intended to represent the greatest pollutant reductions that are
14		economically achievable for an industry. EPA promulgated the Steam Electric
15		Power Generating ELGs in 1974, and amended the regulations in 1977, 1978, 1980,
16		1982, 2015 and 2020. The regulations cover wastewater discharges from steam
17		electric power plants operated by utilities. The Steam Electric regulations are
18		incorporated into NPDES permits issued by the Michigan Department of
19		Environment, Great Lakes & Energy (EGLE).
20		
21	Q11.	Can you describe the recent revisions to EPA's Steam Electric Power
22		Generating (SEPG) ELGs?
23	A11.	Yes. The EPA's SEPG ELGs regulate how electric utilities must manage certain
24		wastewaters. On October 13, 2020, the EPA finalized the ELG Reconsideration
25		Rule which revised some requirements from the 2015 version of the ELG rule. The

#### RJL-5

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Reconsideration Rule revised requirements for two specific waste streams produced by steam electric power plants: flue gas desulfurization (FGD) wastewater and bottom ash transport water (BATW). The Reconsideration Rule provides additional compliance opportunities by finalizing subcategories, such as for the cessation of coal burning activities.

6

#### 7 Q12. When must DTE Electric comply with revised ELGs?

8 A12. The Reconsideration Rule provides opportunities for DTE Electric to evaluate 9 existing ELG compliance strategies and make any necessary adjustments to ensure 10 full compliance with the ELGs in a more cost-effective manner than prior ELG 11 rules. The EPA set the applicability dates for BATW and FGD wastewater retrofits 12 to be "as soon as possible" beginning October 13, 2021, and no later than December 13 31, 2025. For facilities pursuing the FGD wastewater Voluntary Incentives 14 Program, detailed further below, compliance shall be achieved no later than 15 December 31, 2028. Compliance schedules for individual facilities and individual 16 waste streams are determined through issuance of new NPDES permits by EGLE.

17

#### 18 Q13. What are DTE Electric's options for ELG compliance?

19 A13. The Company has two options to achieve compliance under the Reconsideration 20 Rule for BATW and FGD wastewater. The first option is to design and engineer 21 new technologies that are compliant with the ELG requirements for BATW and 22 FGD wastewater. The second option is to pursue a compliance subcategory for 23 BATW and FGD wastewater that EPA established within the Reconsideration 24 Rule. One compliance subcategory allows companies to attain compliance with the 25 ELGs for both BATW and FGD wastewater by ceasing coal burning activities, 1

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which includes retiring coal-fired unit(s) or converting unit(s) to other fuels. If companies certify that unit(s) would retire the use of coal (or refuel), they can continue to operate those units until the unit's specified coal retirement date, which is required to be before December 31, 2028. For the electrical generating unit(s) that certify under this subcategory, companies need to maintain the existing standard limits already in effect for BATW and FGD wastewater discharges.

7

8 In addition to the cessation of coal burning activities subcategory, the 9 Reconsideration Rule also provides a second compliance subcategory specific to 10 FGD wastewater. The Reconsideration Rule established Best Available 11 Technology (BAT) standard discharge limits for FGD wastewater discharges, and 12 further, finalized a subcategory called the Voluntary Incentive Program (VIP). 13 Under the VIP, companies could choose to meet more stringent effluent limits 14 established by EPA based on the model technology of membrane filtration or zero-15 liquid discharge. If a company chooses the VIP option, then the applicability date 16 for FGD wastewater compliance will be December 31, 2028.

17

18To establish compliance for either of these subcategories, companies were required19to submit a Notice of Planned Participation (NOPP) to EGLE by October 13, 2021.

- 20 Once submitted, companies are required to submit annual progress reports to EGLE
- 21 to ensure the commitment of compliance under the subcategories.

#### **R. J. LEE** U-21297

1	Q14.	Can you describe the Cessation of Coal NOPP filing?
2	A14.	Yes. To establish compliance for the cessation of coal compliance subcategory
3		detailed above, companies were required to submit an NOPP to the state permitting
4		agency (EGLE) by October 13, 2021.
5		The cessation of coal NOPP included:
6		(1) identification of the electric generating unit (EGU) intended to achieve
7		permanent cessation of coal combustion,
8		(2) expected date that each EGU is projected to achieve permanent cessation
9		of coal combustion,
10		(3) whether each date represents a retirement or a fuel conversion,
11		(4) whether each retirement or fuel conversion has been approved by a
12		regulatory body, and
13		(5) identification of the relevant regulatory body.
14		
15		In addition, the NOPP must include a copy of the most recent Integrated Resource
16		Plan (IRP) for which the applicable state agency approved the retirement or
17		repowering of the unit subject to the ELGs, certification of EGU cessation under
18		the CCR rule, or other documentation supporting that the EGU will permanently
19		cease the combustion of coal by December 31, 2028. The NOPP must include, for
20		each such EGU, a timeline to achieve the permanent cessation of coal combustion.
21		Each timeline must include interim milestones and the projected dates of
22		completion.
23		
24		A cessation of coal NOPP was submitted for Belle River Power Plant on October
25		13, 2021. At the time of NOPP submittal, preliminary modeling and strategy

1		development related to the Company's long term generation plan and IDD was			
1		development related to the Company's long term generation plan and IKF was			
2		ongoing. Based on these early efforts, the decision to submit the NOPP for Belle			
3		River Power Plant was made. In November 2022, the Company submitted its			
4		updated IRP which included a proposed refueling of Belle River Power Plant units			
5		from coal to natural gas combustion, which was reflective of the Company's NOPP			
6		submitted on October 13, 2021.			
7					
8	Q15.	Can you describe the Voluntary Incentive Program (VIP) NOPP filing?			
9	A15.	Yes. To establish compliance for the VIP compliance subcategory detailed above,			
10		companies were required to submit a VIP NOPP to the state permitting agency			
11		(EGLE), by October 13, 2021.			
12		The VIP NOPP for FGD wastewater included:			
13		(1) Identification of the facility opting to comply with the VIP discharge			
14		requirements,			
15		(2) Specification of technology or technologies that are projected to be used			
16		to comply with those requirements, and			
17		(3) Detailed engineering dependency chart and accompanying narrative			
18		demonstrating when and how the system(s) and any accompanying disposal			
19		requirements will be achieved by December 31, 2028.			
20					
21		A VIP NOPP was submitted for Monroe Power Plant on October 13, 2021.			
22					
23	Q16.	Why did DTE Electric submit the VIP NOPP for FGD ELG compliance?			
24	A16.	The Company evaluated a suite of technology options that would achieve both BAT			
25		and VIP compliance requirements for ELG FGD compliance. At the time of NOPP			

1 development, the Company was still evaluating the suite of potential compliant 2 technologies. To ensure the Company could continue to evaluate all available 3 technologies, including those that achieved VIP compliance, the decision was made 4 to submit the VIP NOPP. By submitting the VIP NOPP, it allowed the Company to 5 continue evaluating all technologies available on the market and not just 6 technologies capable of achieving BAT. 7 8 What is DTE Electric's compliance strategy for Belle River Power Plant? **Q17.** 9 A17. At Belle River Power Plant, fly ash is collected dry and therefore there is no Fly 10 Ash Transport Water (FATW). Additionally, the power plant was constructed and 11 operates without FGDs. Therefore, there is no FGD wastewater. However, the 12 bottom ash is collected using transport water and the ELG Reconsideration Rule 13 requires the Company to achieve compliance with BATW discharge requirements. 14 DTE Electric submitted the NOPP on October 13, 2021, for cessation of coal at 15 Belle River Power Plant. Please see Company Witness Morren's testimony 16 regarding the Company's commitment to convert from coal-fired to natural gas-17 fired operations in 2026. 18 19 Q18. What is DTE Electric's compliance strategy for Monroe Power Plant? 20 A18. At the Monroe Power Plant, the Company is currently implementing projects for 21 FATW ELG compliance according to the 2015 ELG Rule that will cease water 22 discharges related to the transport of fly ash by the end of 2023. For BATW 23 wastewater ELG compliance, the Company must achieve compliance by the end of 24 2025 and will terminate the use of water for bottom ash transport at Monroe Power 25 Plant. For FGD wastewater ELG compliance, the Company can achieve

#### RJL-10

1 compliance based on one of the two compliance options detailed above. The 2 Company has chosen a VIP technology to be installed on Monroe Units 1 and 2 no 3 later than end of 2028. The decision to install a VIP technology is based on preliminary engineering planning and design, cost, and review of compliant 4 5 technology options. Operation and maintenance concerns, project timelines and 6 cost estimates were key factors to selecting the VIP technology instead of a BAT technology. Monroe Units 3 and 4 are projected to retire in 2028, providing 7 8 compliance with the FGD wastewater-portion of the ELG Rule since retirement 9 will eliminate FGD wastewater from these units. Please see Company Witness 10 Morren's testimony for further details regarding ELG compliance.

11

#### 12 Q19. Is EPA currently revising the 2020 ELG Reconsideration Rule?

13 A19. Yes. EPA has initiated a supplemental rulemaking to address discharge limits in 14 the Steam Electric Power Generating category. EPA conducted a science-based 15 review of the 2020 Steam Electric Reconsideration Rule under Executive Order 16 13990, finding that opportunities for improvement exist. Additionally, on January 17 3, 2023, the Unified Agenda of Regulatory and Deregulatory Actions published by 18 the United States Office of Management and Budget was updated and included a 19 new action conducted by EPA related to ELGs. The Agenda stated the EPA, 20 "......is taking direct final action to extend the date for existing coal-fired power 21 plants to submit a notice of planned participation (NOPP) for the permanent 22 cessation of coal combustion subcategory..... from October 13, 2021, to 90 23 days after publication of this rule in the Federal Register." As of January 30, 2023, 24 the EPA has not published this rule in the Federal Register.

25

# Q20. Why is the Company requesting recovery of capital expenditures for projects associated with the 2020 ELG Reconsideration Rule when it is currently under revision?

On August 3, 2021, the EPA issued a Federal Register notice<sup>1</sup> in which they 4 A20. 5 announced their supplemental rulemaking to revise the 2020 ELG Reconsideration 6 Rule as a result of their review conducted under Executive Order 13390. The Notice 7 from EPA states, "While the Agency undertakes this new rulemaking, facilities will 8 continue to be subject to the requirements of the 2015 Rule, as amended by the 9 2020 Rule, which are currently effective." The Notice goes on to also state, "EPA 10 expects permitting authorities to continue to implement the current regulations while the Agency undertakes a new rulemaking." Based on these statements made 11 12 in the August 3, 2021 Federal Register notice by EPA, the Company was required 13 to move forward with the ELG compliance strategy and continue to implement the 14 ELG projects referenced in Q&A9 above. In addition to the Notice, other factors 15 specific to the project such long lead equipment, construction seasons and utilizing 16 periodic outages have also driven the need to move forward with ELG compliance 17 projects.

18

Q21. Other than above, is there other documentation stating that the Company
 must continue implementing ELG compliance projects based on the 2020
 Reconsideration Rule even though EPA is revising it?

A21. Yes, EPA's public webpage<sup>2</sup> in which they detail their 2021 supplemental
 rulemaking to revise the 2020 Reconsideration Rule states, "The current

<sup>&</sup>lt;sup>1</sup> <u>https://www.federalregister.gov/documents/2021/08/03/2021-16354/effluent-limitations-guidelines-and-standards-for-the-steam-electric-power-generating-point-source, accessed January 19, 2023</u>

<sup>&</sup>lt;sup>2</sup> <u>https://www.epa.gov/eg/2021-supplemental-steam-electric-rulemaking</u>, accessed January 19, 2023

Line <u>No.</u>		<b>R. J. LEE</b> U-21297
1		regulations-both the 2015 and 2020 rules-will be implemented and enforced
2		while this supplemental rulemaking is being developed."
3		
4	Q22.	If the Company's IRP is approved, can the Company avoid capital
5		expenditure for bottom ash compliance on the two units proposed to retire in
6		2028 at Monroe?
7	A22.	No. Compliance for bottom ash ELG requirements must be met no later than
8		December 31, 2025. However, as detailed above (Q&A19), the EPA has indicated
9		that they may reopen and extend the timeframe that NOPPs for the cessation of coal
10		compliance subcategory could be submitted. The timing and content of EPA's
11		action is uncertain, and the Company will track EPA's action related to this Unified
12		Agenda entry and respond accordingly.
13		
14	<u>Coal</u>	Combustion Residuals
15	Q23.	Can you describe the EPA's Coal Combustion Residuals (CCR) Rule and its
16		impact on the Company's coal-fired units?
17	A23.	Yes. The EPA's CCR Rule regulates how electric utilities must manage and dispose
18		of coal combustion residuals in landfills and impoundments. On August 28, 2020,
19		the EPA published an amendment to the CCR rule (the Part A Rule) that requires
20		all unlined surface impoundments to cease receipt of waste and initiate closure as
21		soon as technically feasible but by no later than April 11, 2021. The August 28,
22		2020 amendment also provided utilities the ability to request site-specific
23		alternative closure deadlines through a demonstration process requiring EPA
24		approval. On November 12, 2020, EPA published an additional amendment to the
25		CCR rule (the Part B Rule) that allows utilities the opportunity to demonstrate that

1		their unlined surface impoundments have an alternate liner system that is as
2		protective as a CCR rule compliant liner system. The demonstration processes
3		included in the Part A Rule and Part B Rule require EPA approval to continue
4		operating CCR surface impoundments.
5		
6	Q24.	Can you describe the Company's strategy for each CCR unit to comply with
7		the amended closure provisions of the CCR Rule?
8 9	A24.	Yes, see below for a description for each CCR unit.
10		St. Clair Bottom Ash Basins
11		The Company submitted a Part A Rule demonstration for the St. Clair Bottom Ash
12		Basins on November 25, 2020, in accordance with 40 C.F.R. §257.103(f)(2). The
13		demonstration requested an alternative closure deadline based on cessation of coal
14		fired generation in spring of 2022, and a commitment to complete closure of the
15		unit by October 17, 2023. Submission of the Part A Rule demonstration tolled the
16		April 11, 2021 deadline for the unit to cease receipt of waste. On January 11, 2022,
17		the Company received written notice that the Part A Rule demonstration was
18		administratively complete and confirmed that the cease receipt of waste deadline
19		had been tolled until EPA issues a final decision on the demonstration. The
20		Company ceased operation of the coal-fired boilers at St. Clair Power Plant on May
21		31, 2022, completed washdowns of CCR containing equipment on August 12,
22		2022, and commenced physical isolation of the St. Clair Bottom Ash Basins from
23		power plant infrastructure on September 1, 2022. These actions demonstrate that
24		the Company has permanently ceased receipt of CCR and non-CCR waste streams
25		at the St. Clair Bottom Ash Basins and has initiated closure by removal pursuant to

	<b>R. J. LEE</b> U-21297
40 C.F.	.R. §257.102(c). The Company has therefore withdrawn the Part A
demons	tration, as it has already ceased receipt of waste.
Alternat	te Liner Demonstrations:
The Co	mpany submitted Part B applications to EPA on November 30, 2020, to
perform	Alternate Liner Demonstrations for Monroe Fly Ash Basin, Belle River
Bottom	Ash Basins, and Belle River Diversion Basin. The Company received
notice o	of EPA's proposed denial on January 25, 2023. The Company is continuing
with pro	ojects at each facility to comply with the CCR rules and support operating
the plan	ts.
The pro	posed denials affect each facility as follows:
]	Belle River Bottom Ash Basins and Diversion Basin:
	As discussed in Witness Morren's testimony the Company has expedited a
]	project to retrofit the Bottom Ash Basins with a CCR compliant liner system
i	and close the Diversion Basin by removal. The project will be completed
i	in 2023 in accordance with regulatory timelines.
]	Monroe Fly Ash Basin:
,	The Company is already in process of developing alternative capacity at
]	Monroe by converting the existing wet fly ash handling system to a dry
5	system in accordance with the 2015 ELG rule. Once the conversion is
(	complete, the Fly Ash Basin will no longer receive waste and the Company

Line <u>No.</u>

23 will initiate closure in 2023 within the appropriate regulatory timeframes.

<u> </u>	
1	River Rouge Bottom Ash Basin
2	As discussed in Company Witness Morren's testimony, the Company has removed
3	all ash from the River Rouge Bottom Ash Basin and converted it to a non-CCR
4	basin. The physical removal of coal ash was certified as complete on November
5	12, 2020, allowing the basin to continue to operate as a non-CCR wastewater
6	treatment basin.
7	Monroe Bottom Ash Basin
8	The Company ceased receipt of CCR at the Monroe Bottom Ash Basin prior to the
9	effective date of the 2015 CCR rule. Consequently, the Company prepared and
10	placed in the facility's operating record a notice of intent to initiate closure on
11	December 11, 2015, in accordance with §257.100. The Monroe Bottom Ash Basin
12	was therefore considered an inactive CCR surface impoundment. Section 257.100
13	was later remanded and revised by EPA, subjecting inactive CCR surface
14	impoundments to all the requirements applicable to existing CCR surface
15	impoundments but on an alternative timeframe. In April 2020, it was determined
16	that the Monroe Bottom Ash Basin did not meet the requirements of §257.60
17	(placement above the uppermost aquifer) and was subject to closure for cause under
18	the requirements of §257.101(b)(1)(i) and therefore must cease receipt of both CCR
19	and non-CCR waste streams as soon as technically feasible, but no later than April
20	11, 2021, and close in accordance with §257.102. The Company ceased receipt of
21	non-CCR waste streams and initiated closure on October 21, 2020 and is currently
22	progressing through closure by removal of all CCR.

1	Sibley Quarry Landfill
2	Improvements to infrastructure at Sibley Quarry Landfill have been made to
3	enhance the storage capability to accept the CCR material coming from the Monroe
4	Bottom Ash Basin and as alternative capacity for Monroe Power Plant production
5	CCR. These projects were necessary because the Monroe Fly Ash Basin and
6	Vertical Extension Landfill could not accept the volume of CCR material
7	anticipated to be removed from the Monroe Bottom Ash Basin and operate through
8	its useful life without physical and or permit modifications. Sibley Quarry Landfill
9	did not have the same permitted capacity constraints and was therefore selected as
10	the disposal location for the CCR material removed from the Monroe Bottom Ash
11	Basin. Sibley Quarry Landfill also serves as alternative capacity for Monroe Power
12	Plant production CCR if EPA's proposed denial of the Monroe Fly Ash Basin
13	alternate liner demonstration application becomes final. The Company has
14	transported 0.6 million cubic yards from the Monroe Bottom Ash Basin through
15	2022 and will transport most of the remaining material in 2023. Certification of
16	closure of the Monroe Bottom Ash Basin is expected by Summer 2024. Company
17	Witness Morren details the costs associated with these projects.
18	

# 19 Q25. Does this complete your direct testimony?

20 A25. Yes, it does.

## **STATE OF MICHIGAN**

#### **BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

In the matter of the Application of	)
DTE ELECTRIC COMPANY	)
for authority to increase its rates, amend	)
its rate schedules and rules governing the	)
distribution and supply of electric energy, and	)
for miscellaneous accounting authority.	)

Case No. U-21297

QUALIFICATIONS

AND

#### DIRECT TESTIMONY

OF

#### TIMOTHY J. LEPCZYK

## DTE ELECTRIC COMPANY QUALIFICATIONS AND DIRECT TESTIMONY OF TIMOTHY J. LEPCZYK

Line <u>No.</u>

1	Q1.	What is your name, business address and by whom are you employed?
2	A1.	My name is Timothy J. Lepczyk (he/him/his). My business address is DTE Energy
3		Company, One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE
4		Energy Corporate Services, LLC as Assistant Treasurer and Director of Corporate
5		Finance, Insurance and Development.
6		
7	Q2.	On whose behalf are you testifying?
8	A2.	I am testifying on behalf of DTE Electric Company (DTE Electric or Company).
9		
10	Q3.	What is your educational background?
11	A3.	I graduated from Georgetown University in 2004 with a Bachelor of Business
12		Administration degree, with a concentration in International Business. In 2008, I
13		graduated with my MBA from the University of Michigan, with a focus in Finance
14		and Corporate Strategy.
15		
16	Q4.	What is your work experience?
17	A4.	I began my employment with Ford Motor Company in the summer of 2004 as a
18		financial analyst within that company's Dearborn Stamping facility. In 2006, I left
19		to pursue my MBA. In 2008, after graduation, I went to work for Booz & Company,
20		a management consultancy, where I focused on the automotive and industrial
21		sectors. I worked at Booz & Company from 2008 until 2013 when I joined DTE
22		Energy.
23		
24		In 2013, I joined DTE Energy as a Manager on the Corporate Strategy team where
25		I was the lead analyst for various projects and studies primarily relating to the Gas

1		Storage and Pipeline business. In 2014, I formally accepted a position within the
2		Gas Storage and Pipeline team as Manager in their strategy group where I was
3		responsible for various economic analyses (e.g., natural gas supply and demand
4		fundamentals) and for assessing potential new acquisition opportunities. In 2016, I
5		accepted the position of Manager for the Corporate Development team where I was
6		responsible for managing DTE Energy's capital investment process and various
7		valuation processes (for example, DTE Energy's annual Goodwill impairment
8		assessment). In addition, I led broader strategy initiatives including the analysis,
9		which ultimately led to our decision to spin off the Midstream business segment.
10		
11		In 2021, I accepted my current position, Assistant Treasurer and Director of
12		Corporate Finance, Insurance and Development.
13		
13 14	Q5.	What are your current duties and responsibilities?
13 14 15	<b>Q5.</b> A5.	What are your current duties and responsibilities? I am responsible for assisting the Treasurer in managing the capital needs of the
13 14 15 16	<b>Q5.</b> A5.	What are your current duties and responsibilities? I am responsible for assisting the Treasurer in managing the capital needs of the Company. These responsibilities include managing corporate liquidity and
13 14 15 16 17	<b>Q5.</b> A5.	What are your current duties and responsibilities? I am responsible for assisting the Treasurer in managing the capital needs of the Company. These responsibilities include managing corporate liquidity and financing activities such as the raising of both equity capital and capital markets
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> </ol>	<b>Q5.</b> A5.	What are your current duties and responsibilities? I am responsible for assisting the Treasurer in managing the capital needs of the Company. These responsibilities include managing corporate liquidity and financing activities such as the raising of both equity capital and capital markets debt for DTE Energy, DTE Electric, and DTE Gas Company (DTE Gas). I assist
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> </ol>	<b>Q5.</b> A5.	What are your current duties and responsibilities? I am responsible for assisting the Treasurer in managing the capital needs of the Company. These responsibilities include managing corporate liquidity and financing activities such as the raising of both equity capital and capital markets debt for DTE Energy, DTE Electric, and DTE Gas Company (DTE Gas). I assist in maintaining relationships with the commercial and investment banking
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> </ol>	<b>Q5.</b> A5.	What are your current duties and responsibilities? I am responsible for assisting the Treasurer in managing the capital needs of the Company. These responsibilities include managing corporate liquidity and financing activities such as the raising of both equity capital and capital markets debt for DTE Energy, DTE Electric, and DTE Gas Company (DTE Gas). I assist in maintaining relationships with the commercial and investment banking community, interact with the rating agencies, and execute corporate financial
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> </ol>	<b>Q5.</b> A5.	What are your current duties and responsibilities? I am responsible for assisting the Treasurer in managing the capital needs of the Company. These responsibilities include managing corporate liquidity and financing activities such as the raising of both equity capital and capital markets debt for DTE Energy, DTE Electric, and DTE Gas Company (DTE Gas). I assist in maintaining relationships with the commercial and investment banking community, interact with the rating agencies, and execute corporate financial policies, particularly in the areas of balance sheet management, debt issuances, and
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> </ol>	<b>Q5.</b> A5.	What are your current duties and responsibilities? I am responsible for assisting the Treasurer in managing the capital needs of the Company. These responsibilities include managing corporate liquidity and financing activities such as the raising of both equity capital and capital markets debt for DTE Energy, DTE Electric, and DTE Gas Company (DTE Gas). I assist in maintaining relationships with the commercial and investment banking community, interact with the rating agencies, and execute corporate financial policies, particularly in the areas of balance sheet management, debt issuances, and agency ratings. In addition, I manage the Company's capital investment approval
<ol> <li>13</li> <li>14</li> <li>15</li> <li>16</li> <li>17</li> <li>18</li> <li>19</li> <li>20</li> <li>21</li> <li>22</li> <li>23</li> </ol>	<b>Q5.</b> A5.	What are your current duties and responsibilities? I am responsible for assisting the Treasurer in managing the capital needs of the Company. These responsibilities include managing corporate liquidity and financing activities such as the raising of both equity capital and capital markets debt for DTE Energy, DTE Electric, and DTE Gas Company (DTE Gas). I assist in maintaining relationships with the commercial and investment banking community, interact with the rating agencies, and execute corporate financial policies, particularly in the areas of balance sheet management, debt issuances, and agency ratings. In addition, I manage the Company's capital investment approval and review process along with managing the Company's property and liability

#### Line <u>No.</u>

1	Q6.	Have you previously sponsored testimony before the Michigan Public Service		
2		Commission	(MPSC or Commission)?	
3	A6.	Yes, I have. I have sponsored testimony in the following cases:		
4		U-20836	DTE Electric 2022 General Rate Case	
5		U-21193	DTE Electric 2022 Integrated Resource Plan	

#### Line No

Ν	0	•

# 1 Purpose of Testimony

2	Q7.	What is the purpose of your testimony in this proceeding?				
3	A7.	The purpo	The purpose of my testimony is to support DTE Electric's projected capital			
4		structure a	nd the cost of its	long- and short-term debt to be used in the determination		
5		of DTE Ele	of DTE Electric's overall rate of return in this proceeding.			
6						
7	Q8.	How is yo	ur testimony or	ganized?		
8	A8.	My testime	ony is organized	as follows:		
9		I. Sur	nmary of Recom	nmendations		
10		II. Dev	velopment of Ca	pital Structure		
11		III. Dev	velopment of Co	st Rates		
12		IV Sec	curitization			
13		V. Sur	nmary and Conc	lusions		
14						
15	Q9.	Are you sponsoring any exhibits in this proceeding?				
16	A9.	Yes. I am	Yes. I am supporting the following exhibits:			
17		<u>Exhibit</u>	<u>Schedule</u>	Description		
18		A-1	A2	Historical Financial Metrics		
19		A-4	D2	Cost of Long-Term Debt – as of December 31, 2021		
20		A-4	D3	Cost of Short-Term Debt – Twelve Month		
21				Period Ended December 31, 2021		
22		A-4	D4	Cost of Preferred and Preference Stock - Twelve		
23				Month Period Ended December 31, 2021		
24		A-4	D5	Cost of Common Shareholders' Equity - Twelve		
25				Month Period Ended December 31, 2021		

				Т. Ј. LEPCZYK		
Line <u>No.</u>				U-21297		
1		A-11	A2	Projected Financial Metrics		
2		A-14	D1.1	Peer Group Common Equity		
3		A-14	D2	Cost of Long-Term Debt – as of November 30, 2024		
4		A-14	D3	Cost of Short-Term Debt – Twelve Month		
5				Period Ended November 30, 2024		
6		A-14	D4	Cost of Preferred and Preference Stock - Twelve		
7				Month Period Ended November 30, 2024		
8		A-18	H1	Current and Historical Credit Ratings		
9		A-18	H2	Recent Utility Corporate Bond Issuances		
10						
11	Q10.	Were these exhibits prepared by you or under your direction?				
12	A10.	Yes, they we	re.			
13						
14	<u>I.</u>	SUMMARY OF RECOMMENDATIONS				
15	Q11.	What permanent capital structure are you recommending for the projected				
16		test year to be utilized in determining the overall rate of return calculation for				
17		DTE Electric?				
18	A11.	I am recommending a projected permanent capital structure of 50% long-term debt				
19		and 50% common equity. Permanent capital is long-term perpetual capital.				
20		Common equity, preferred stock and long-term debt are sources of permanent				
21		capital. Since the Company does not have any preferred stock, I am recommending				
22		the permanent capital structure to be made up of 50% long-term debt and 50%				
23		common equity. This permanent capital structure is reflected in DTE Electric's				
24		projected permanent capital structure as of November 30, 2024, as shown in Exhibit				
25		A-14, Schedule D1, which is supported by Company Witness Vangilder. This				

		T. J. LEPCZYK
Line <u>No.</u>		U-21297
1		capital structure is necessitated by the business and financial risks confronting DTE
2		Electric, which I will discuss in greater detail later in my testimony.
3		
4	Q12.	What is your forecast for DTE Electric's cost of long-term debt, short-term
5		debt, and preferred stock for the 12-month period ending November 30, 2024?
6	A12.	I am forecasting 4.06% for the cost of DTE Electric's long-term debt, and 4.98%
7		for the cost of DTE Electric's short-term debt. The Company does not have
8		preferred stock and therefore it has no cost rate. Exhibit A-14, Schedule D2
9		supports the cost rate for long-term debt. Exhibit A-14, Schedule D3 supports the
10		cost rate for short-term debt.
11		
12	<u>II.</u>	DEVELOPMENT OF CAPITAL STRUCTURE
13	Q13.	What do you mean by capital structure?
14	A13.	A company's capital structure includes the amount of equity and debt necessary to
15		support the operations of its business and is defined differently by regulators,
16		finance professionals and rating agencies. Total regulatory capital structure
17		typically includes long-term debt, short-term debt, preferred stock, common equity,
18		deferred taxes, deferred job development investment tax credits, and deferred
19		investment tax credits. Permanent capital structure includes only long-term debt
20		and equity. Rating agencies calculate a company's capital structure using short-
21		term debt, long-term debt, preferred stock, common equity and other adjustments.
22		The rating agencies adjust debt to include items like capital and operating leases,
23		unfunded pension liabilities, power purchase agreements and asset retirement
24		obligations.

25

1 Q14. Why is a sound capital structure important? 2 A14. It is important to have a financially sound capital structure in order to ensure that a 3 company can obtain needed capital. A sound capital structure produces capital 4 costs that are reasonable and equitable. Also, it is important that the overall return 5 on capital be sufficient to assure financial confidence in a firm and to allow it to 6 raise the funds that are necessary to operate its business at reasonable costs and 7 terms. A sound capital structure is in the best interests of the customers as it ensures 8 the continued viability of the company. 9 10 Q15. How does risk affect a firm's capital structure? 11 A15. In general, a firm such as DTE Electric faces two types of risk: business risk and 12 financial risk. Business risk is a result of systemic and non-systemic risk. Systemic 13 risks are broad economic risks faced by all firms. Non-systemic risks are risks 14 specifically identified as those faced by the individual firm. Financial risk is the 15 risk that common equity shareholders face to the extent that a firm issues debt to 16 finance real assets. Debtholders (also known as bondholders) have priority over 17 equity shareholders in the event of corporate bankruptcy. Thus, the greater the 18 amount of debt held by a firm, the greater the risk to equity shareholders. It is 19 essential that a firm recognizes the dynamics of these risks and adjusts its 20 underlying debt and equity components to produce a sound capital structure. 21 22 Q16. How does a company's capital structure impact its ability to attract capital?

23 A16. Having a weak or highly leveraged capital structure may lead to higher required 24 returns on equity and a higher cost of debt. It also can impact the company's ability 25 to obtain capital. For example, a company with a highly leveraged capital structure

Line No.

<u>No.</u>
1 may lose its investment grade rating from the rating agencies. Non-investment
2 grade companies have a limited investor base and a more limited access to capital
3 than investment grade companies. Moreover, during periods of diminished capital
4 liquidity, even investment grade companies can have limited access to new capital
5 sources. It is important to consider how extreme market reactions to singular events
6 impact how easily capital will be able to be accessed during the future test period
7 should an unforeseen market shock occur. Furthermore, rating agencies allow little
8 or no time for a company to correct and improve its capital structure before

- 9 lowering its credit rating. Conversely, companies must be proactive to target and 10 achieve the midpoint of the range of rating agency financial metrics to have a better 11 chance to maintain current ratings.
- 12

Line

#### 13 **Q17.** Will higher debt levels in a capital structure affect the cost of debt?

- 14 A17. Yes. The cost of debt increases as more debt is added to the capital structure. 15 Further, higher debt levels can increase the risk of a downgrade by the rating 16 agencies. A lower credit rating means greater credit risk such that investors will 17 require a higher return to invest in a company, thereby increasing the cost of debt 18 for that company.
- 19

#### 20 Q18. For DTE Electric's defined projected test year, what capital structure are you 21 recommending for DTE Electric in the instant case?

22 A18. For the projected test year, the permanent capital structure that I am recommending 23 includes long-term debt and equity as shown on Exhibit A-14, Schedule D1, that is 24 supported by Witness Vangilder. Within this regulatory capital structure, I am 25 recommending a projected test year permanent capital structure that has 50% long-

TJL-8

T in a		T. J. LEPCZYK
Line <u>No.</u>		0-21297
1		term debt and 50% common equity. This is the same permanent capital structure
2		authorized by the Commission in the last general rate case, Case No. U-20836.
3		
4	Q19.	Does the Company believe that a 50/50 capital structure is the optimal capital
5		structure for DTE Electric?
6	A19.	No. To reduce the number of contested positions in the instant case, the Company
7		is using the structure authorized in the November 18, 2022 order in Case No. U-
8		20836. However, as the Company has argued in past rate cases, it believes the more
9		appropriate capital structure for DTE Electric is closer to that of its peers. Exhibit
10		A-14, Schedule D1.1 shows DTE Electric peers having a capital structure made up
11		of 48% long-term debt and 52% common equity. A 50% equity level gives the
12		Company less protection in the event of an unforeseen market event and may
13		impact DTE Electric's ability to access capital during the future test period should
14		an unforeseen market shock occur.
15		
16	Q20.	Is the proposed ratio of 50% common equity to total permanent capitalization
17		in line with DTE Electric's peers?
18	A20.	No. The common equity ratio requested in the instant case is lower than that of the
19		Company's peers. As shown on Exhibit A-14 Schedule D1.1, the average equity
20		ratio for DTE Electric peers was approximately 52%. DTE Electric's targeted 50%
21		equity ratio is a reasonable level given that the average ratio of the peer group is
22		higher at 52%. The data was obtained from S&P Global Market Intelligence (SNL)
23		for the most recent fiscal year available per peer company.
24		DTE Electric believes its requested 50% is reasonable and below the equity ratio
25		of its peers across the country and within Michigan.

TJL-9

#### Line No.

# Q21. Does the intense capital investment program contribute to the need for a higher level of equity in general within the capital structure?

3 A21. Yes, it is imperative that DTE Electric be viewed as a financially sound firm with 4 a solid investment grade rating to ensure the reasonableness and competitiveness 5 of capital costs. DTE Electric will be financing and funding over \$7.6 billion of 6 electric capital expenditures for the period January 2022 through November 2024 7 (see Exhibit A-12 Schedule B5). In a period of intense capital investment, a sound 8 capital structure and a favorable regulatory environment are essential to maintain 9 the financial well-being of the Company. Should the Company face any unforeseen 10 or negative impacts to its financial health, a higher equity balance may be needed. 11 The common equity balance and equity ratio projected for the test year in the instant 12 case will hopefully enable the Company to maintain strong credit ratings and 13 withstand any shocks in the financial markets, thereby ensuring a smooth 14 implementation of its capital expenditure program.

15

# 16 Q22. Is DTE Electric committed to maintaining a 50% equity ratio in its capital 17 structure?

18 Yes. At December 31, 2021, DTE Electric's equity ratio was 50%. DTE Electric A22. is committed to maintaining a 50% equity ratio and has demonstrated its 19 20 commitment to its targeted equity ratio by receiving equity infusions from DTE 21 Energy. DTE Energy has made reasonable efforts to strengthen DTE Electric's 22 credit quality by infusing over \$1.8 billion of common equity from 2017-2021. 23 DTE Electric has received equity infusions totaling \$599 million in 2022 and will 24 infuse the amounts necessary in future years to maintain a 50% common equity 25 ratio.

Line <u>No.</u>

1	<u>III.</u>	DEVELOPMENT OF COST RATES
2	Q23.	What were DTE Electric's historical financial and ratemaking metrics from
3		2017 through 2021?
4	A23.	DTE Electric's historical financial and ratemaking metrics for each of the previous
5		five years (2017 through 2021) are detailed in Exhibit A-1, Schedule A2. The
6		historical financial calculations include year-end financial metrics and are
7		calculated on a financial basis from DTE Electric's financial reports. The historical
8		ratemaking metrics include year-end financial metrics and are calculated from DTE
9		Electric's annual regulatory filings.
10		
11	Q24.	What is the cost of long-term debt outstanding at December 31, 2021?
12	A24.	Exhibit A-4, Schedule D2 calculates the cost of the long-term debt outstanding at
13		December 31, 2021. As shown in the exhibit and schedule, the cost of long-term
14		debt also includes agent's fees, commissions and financing expenses and is
15		calculated on the net proceeds to the Company. The weighted average cost of debt
16		is computed based on the total annual costs to the Company divided by the total
17		principal amount outstanding at year-end. The cost of long-term debt at December
18		31, 2021 was 3.80%.
19		
20	Q25.	What is the cost of short-term debt outstanding at December 31, 2021?
21	A25.	The cost of short-term borrowings for the 13-month period ended December 31,
22		2021 was 3.02%. The cost of short-term debt consists of the 1) interest rate on short-
23		term borrowings, and 2) credit facility fees associated with the credit agreements
24		necessary for the issuance of short-term debt. See Exhibit A-4, Schedule D3.
25		

1	Q26.	What was the approved cost of equity as of December 31, 2021?
2	A26.	DTE Electric's authorized cost of common shareholders' equity as of December
3		31, 2021 was 9.9% and was approved in Case No. U-20561. DTE Electric does not
4		have any preferred stock. See Exhibit A-4, Schedules D4 and D5.
5		
6	Q27.	What does DTE Electric project its financial metrics to be in the projected test
7		year?
8	A27.	DTE Electric's forecasted ratemaking metrics are available in Exhibit A-11,
9		Schedule A2. Forecasted calculations include metrics for the fully projected test
10		year. The forecasted ratemaking metrics for the projected test year are to be
11		reported assuming (i) full rate relief as requested, and (ii) zero rate relief.
12		
13	Q28.	What is the purpose of Exhibit A-14, Schedule D2?
14	A28.	The purpose of Exhibit A-14, Schedule D2 is to calculate DTE Electric's projected
15		weighted average long-term debt costs as of November 30, 2024. Starting with the
16		actual December 31, 2021 long-term debt outstanding, any known and measurable
17		changes for each year were made to arrive at the projected balance as of November
18		30, 2024. Known and measurable changes that have occurred or are projected to
19 20		occur from January 1, 2022 through November 30, 2024 include:

#### Line <u>No.</u>

1

Long-Term Debt Activity	Amount	Date	Interest
Long-Term Deot Activity	(\$000)	Date	Rate
Issuance	500,000	Feb-22	3.00%
Issuance	400,000	Feb-22	3.65%
Redemption	(250,000)	Mar-22	2.65%
Redemption	(66,000)	Sep-22	6.95%
Issuance	920,000	Mar-23	5.25%
Issuance	150,000	May-23	5.25%
Redemption	(102,000)	Sep-23	4.31%
Redemption	(100,000)	Oct-23	5.19%
Issuance	945,000	Mar-24	5.50%
Redemption	(400,000)	Mar-24	3.65%
Net change in debt	1,997,000		

Table 1 Is	suances and	Redemptions
------------	-------------	-------------

The 2023 and 2024 debt issuances are assumed to be 30-year fixed rate bonds with an interest rate of 5.25% and 5.50%, respectively. The interest rate for the debt issuances is based on forward 30-year Treasury rates and adding a spread of 137.5 basis points which is the current spread on 30-year utility debt. Including the planned long-term debt issuance, the weighted average long-term debt cost as of November 30, 2024 is projected to be 4.06%.

10

2 3

#### 11 Q29. Why did you use long-term debt cost on a net proceeds basis?

12 A29. The actual costs would be understated if the net proceeds were not used in the base 13 calculation. The net proceeds methodology accounts for underwriters' 14 compensation and other financing expenses and is shown on Exhibit A-14, 15 Schedule D2. A portion of any amount financed is used to fund these costs, such 16 that the Company has access to less than the full amount financed. As a result, 17 these fees and expenses are shown as a reduction in proceeds from the issuance of

<b>T. J. LEPCZY</b> U-212		Line <u>No.</u>	-
new securities, thereby increasing the effective cost of the issuance above the stat	n	1	
coupon rate.	C	2	
		3	
Q30. How did you determine the interest rate on short-term debt on Exhibit A-1	<b>30.</b> H	4	
Schedule D3?	S	5	
A30. The total cost of short-term debt is comprised of the interest rate on the short-ter	30. T	6	
debt plus associated facility fees. Supporting credit facilities are required by t	d	7	
rating agencies and investors for DTE Electric to issue commercial paper. The	ra	8	
facilities have costs associated with them. The interest rate on the short-term de	fa	9	
was determined by adding 40 basis points (bps) to the 1-month short-term inde	W	10	
A spread of 40 bps was added to the index because that is the historical spread	А	11	
DTE Electric's commercial paper issuances. See Exhibit A-14, Schedule D3.	D	12	
		13	
The average forecast for the 1-month short-term index for the 13-month period	Т	14	
ending November 30, 2024 is 4.12%. Adding the spread of 40 bps to the ind	e	15	
brings the interest rate on short-term borrowings to a total of 4.52%. The cost	b	16	
the facility fees for the 12-month period ending November 30, 2024, is \$1.5 million	tł	17	
This cost was divided by the average outstanding short-term debt balance of \$3.	Т	18	
million and equates to 0.46% of the cost of short-term debt. Adding the interest	n	19	
rate on short-term debt of 4.52% to the facility fee cost of 0.46%, results in the to	ra	20	
cost of short-term debt of 4.98%.	C	21	
		22	
Q31. What is the purpose of Exhibit A-14, Schedule D4?	31. V	23	
A31. Exhibit A-14, Schedule D4 shows that DTE Electric does not plan to have preferr	31. E	24	
or preference stock during the projected test period.	0	25	

## TJL-14
1	Q32.	What are the Company's current and historical credit ratings?
2	A32.	Exhibit A-18, Schedule H1 shows DTE Electric's and DTE Energy's current and
3		historical credit ratings, along with associated rating agency outlooks, for the
4		previous five years as published by Standard & Poor's (S&P), Moody's Investors
5		Service (Moody's), and Fitch Ratings. The credit ratings include senior unsecured
6		debt, senior secured debt, and commercial paper ratings.
7		
8	Q33.	Have there been recent public utility bond issuances?
9	A33.	Yes. I have provided details of public utility bond issuances for the three-month
10		period prior to, through the three-month period after, each of DTE Electric's long-
11		term debt offerings issued during the 24 months prior to November of 2022. This
12		summary includes the offer date, issuing company, type of offering (either secured
13		or unsecured), Moody's and S&P credit ratings, maturity, tenor, amount of offering,
14		coupon, and issue spread. See Exhibit A-18, Schedule H2.
15		
16	IV.	SECURITIZATION
17	Q34.	Does the Company intend to securitize additional regulatory assets?
18	A34.	Yes. In the June 23, 2021 order in Case No. U-21015, the Commission approved
19		the securitization of \$73.2 million of River Rouge net plant and \$156.9 million of
20		ongoing tree trimming surge regulatory assets. The securitization financing was
21		completed in March of 2022. The Company is planning to securitize the net book
22		balance associated with the St. Clair and Trenton "Tier 2" coal plants which were
23		retired in 2022 before the end of their respective useful lives. The Company plans
24		to submit a filing to securitize these assets in 2023. Additionally, the Company is

Line <u>No.</u>

Line <u>No.</u>		<b>T. J. LEPCZYK</b> U-21297
1		planning a future securitization of the tree trim regulatory assets once the balance
2		is large enough to make a financing feasible.
3		
4	Q35.	How has the tree trim surge regulatory asset been financed in prior rate
5		cases?
6	A35.	On May 2, 2019, the Commission issued its order in Case No. U-20162 whereby
7		the Company was authorized a return on the tree trim surge regulatory asset at the
8		short-term debt cost rate of 3.56%. (p. 80). In Case No. U-20561 and Case No U-
9		20836, the return on tree trim surge regulatory asset was calculated at the authorized
10		short-term debt rate.
11		
12	Q36.	What does the Company believe is the appropriate financing rate for tree-trim
13		assets?
14	A36.	Given the temporary status, defined in Case No. U-20162, of the Tree Trim Surge
15		regulatory asset, the Company did not pursue financing with permanent long-term
16		debt and equity capital, but rather financed with short-term working capital
17		including short-term debt. Thus, this was matching the financing costs with the
18		return the Company was earning on the regulatory asset. In securitization Case No.
19		U-21015, the Commission considered the regulatory asset to have been financed
20		with permanent capital and specified that proceeds of the securitization should be
21		used for the repayment of long-term debt and equity. Consistent with that financing
22		order, the Company's position is that any future tree trim surge regulatory asset
23		amounts should be treated as being financed with permanent long-term debt and
24		equity capital and receive the respective return.
25		

# Q37. How does the Company propose to treat the tree trim surge regulatory asset in this instant case?

3 A37. In Case No. U-20836, the Company again recommended that any future tree 4 trimming surge expenditures be financed through the issuance of long-term debt 5 and equity until the time the Company can execute a securitization financing for 6 these amounts. The Commission's order in that case disallowed the Company's 7 recommendation and ordered a return based on the short-term debt rate. Although 8 the Company believes the appropriate financing is through long-term debt and 9 equity to match how the proceeds of securitization would be applied, to reduce the 10 number of contested positions in this instant case, I have directed Witness 11 Vangilder to calculate the return on projected tree trim surge regulatory asset using 12 the cost of short-term debt.

13

## 14 Q38. Can you please summarize why amounts securitized should be reduced by

#### 15

## the related deferred taxes?

16 A38. Yes. It is undisputed that the Company uses a mix of debt, equity, and deferred 17 taxes to finance its overall rate base. It is illogical to ignore the deferred taxes 18 related to the St. Clair and Trenton "Tier 2" coal plants and Tree Trim Surge 19 investments, and it is unjust, unreasonable, and inequitable to require the Company 20 to retire equity and debt in excess of those amounts currently used to finance the 21 assets. The cash benefit derived from accumulating the deferred tax liability has 22 been used to the benefit of our customers (e.g., the cash benefit has reduced the 23 amount of debt and equity financing the assets, thus lowering the "return on" 24 component of the revenue requirement). The "gross" securitization methodology 25 unfairly penalizes the Company by requiring the purchase of equity and debt in excess of those amounts used to finance these specific assets. In effect, via the
 "gross" methodology, the Company is forced to purchase debt and equity used to
 finance assets unrelated to the net plant and / or regulatory asset to be securitized.
 Therefore, it is the Company's position the Commission should allow the "net of
 tax" approach.

6

## 7 Q39. How are securitization assets accounted for in this rate case?

A39. Although the Company's position is that the "net of tax" approach is the more
appropriate methodology, in order to reduce the number of contested positions in
this instant case, for purposes of modeling, the Company has utilized the "gross"
methodology.

12

## 13 V. SUMMARY AND CONCLUSIONS

### 14 Q40. Can you summarize your recommendation and conclusions?

15 A40. Due to the financial and business risks faced by the Company, a projected 16 permanent capital structure of 50% long-term debt and 50% common equity is 17 reasonable and prudent. DTE Energy has taken reasonable actions to strengthen 18 DTE Electric's credit quality and has done so by infusing over \$1.8 billion of 19 common equity from 2017 through 2021 and will continue to do so as needed. The 20 plan calls for additional equity infusions and retained earnings growth through the 21 projected test period in the amount necessary to maintain the Company at no less 22 than a ratio of 50% equity to permanent capital at November 30, 2024. For the 23 projected year, the cost of short-term debt is projected to be 4.98%, and the cost of 24 long-term debt is projected to be 4.06%. I believe these expenses and measures are 25 reasonable, prudent and necessary.

Line	<b>T. J. LEPCZYK</b> U-21297
<u>No.</u>	
1	

- Q41. Does this complete your direct testimony? 2
- 3 A41. Yes, it does.