

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of
DTE Electric Company to increase its Case No. U-21534
rates, amend its rate schedules and
rules governing the distribution and Volume No. 3
supply of electric energy, and for
miscellaneous accounting authority.

CROSS-EXAMINATION

Proceedings held via Microsoft Teams in the
above-entitled matter before Sally L. Wallace, J.D.,
Administrative Law Judge with MOAHR, for the Michigan
Public Service Commission, Lansing, Michigan, on
Thursday, September 5, 2024, at 9:01 a.m.

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22 - - -

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17	MEC-69	Discovery MNSCDE-20.12, -20-13, -20-14	610	610
18	MEC-70	Ann TT Reports 2023-2020	610	610
19	MEC-71	WP AJK U-21534 GPM.xlsx	532	533
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1 Thursday, September 5, 2024

2 At 9:01 a.m.

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4 (Hearing resumes following adjournment of Wednesday,
5 September 4, 2024.)

6 JUDGE WALLACE: All right. We are back
7 on the record in Case No. U-21534, In the matter of the
8 application of DTE Electric for authority to increase its
9 rates, amend its rate schedules and rules governing the
10 distribution and supply of electric energy, and for
11 miscellaneous accounting authority. I'm Sally Wallace,
12 I'm the Administrative Law Judge who's been assigned to
13 preside over this hearing. As I noted yesterday, the
14 Commission will be reading the record in this case, I
15 will not be preparing a PFD.

16 O.K. Starting out with appearances
17 today, Ms. Hayden.

18 MS. HAYDEN: Good morning, your Honor.
19 Andrea Hayden and Jon Christinidis on behalf of DTE
20 Electric Company.

21 JUDGE WALLACE: Good morning. Mr. Singh.

22 MR. SINGH: Good morning, your Honor.
23 Amit Singh on behalf of Michigan Public Service
24 Commission Staff.

25 JUDGE WALLACE: Good morning, Mr. Singh.

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1 Mr. King, Assistant Attorney General King.

2 MR. KING: Good morning, your Honor.

3 Joel King on behalf of Attorney General Dana Nessel.

4 JUDGE WALLACE: Good morning, Mr. King.

5 Ms. Andrews.

6 MS. ANDREWS: Good morning, your Honor.

7 T.J. Andrews, and I'll make an appearance this morning

8 for Chris Bzdok on behalf of MNSC.

9 JUDGE WALLACE: Good morning.

10 Mr. Abrams.

11 MR. ABRAMS: Good morning, your Honor.

12 Daniel Abrams appearing on behalf of the Ecology Center,

13 the Environmental Law & Policy Center, the Union of

14 Concerned Scientists, and Vote Solar, collectively the

15 Clean Energy Organizations.

16 JUDGE WALLACE: Mr. Ooms. (No response.)

17 O.K. Mr. Boehm. (No response.)

18 I think Ms. Brader said they would be in

19 and out. Is Ms. Brader here? (No response.) No.

20 Mr. Templeton.

21 MR. TEMPLETON: Good morning, your Honor.

22 Mark Templeton of the Abrams Environmental Law Clinic

23 representing Souldarity and We Want Green, Too,

24 collectively known as the Detroit Area Advocacy

25 Organizations in this proceeding. Also entering an

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1 appearance on behalf of my colleague Jacob Schuhardt.
2 Thank you, your Honor.

3 JUDGE WALLACE: Good morning,
4 Mr. Templeton. Ms. Horne.

5 MS. HORNE: Good morning, your Honor.
6 Melissa Horne on behalf of Walmart, Inc.

7 JUDGE WALLACE: Good morning.
8 Mr. Campbell.

9 MR. CAMPBELL: Good morning, your Honor.
10 Steve Campbell of Clark Hill, PLC, on behalf of the
11 Association of Businesses Advocating Tariff Equity.
12 Similar to yesterday, as we don't have any planned cross
13 today, I don't plan on attending the entire hearing.

14 JUDGE WALLACE: O.K. Thank you.
15 Mr. Vijaykar. (No response.)

16 O.K. Mr. Bright.

17 MR. BRIGHT: Good morning, your Honor.
18 Stephen Bright on behalf of Electrify America, LLC. We
19 will also be in and out today as we do not have any
20 cross.

21 JUDGE WALLACE: O.K. Thank you. And I
22 think Mr. Keskey had indicated that they would not be
23 back until we were binding in. Mr. Keskey or Mr. Coyer
24 here? (No response.)

25 O.K. Did I miss anyone?

1 MS. JACKSON: Good morning, your Honor.
2 This is Valerie Jackson on behalf of the City of Ann
3 Arbor. As you said, Valerie Brader is off today, but I
4 am here for the City of Ann Arbor.

5 JUDGE WALLACE: Great. Thank you,
6 Ms. Jackson. Sorry I missed you there. Anyone else I
7 missed? (No response.)

8 All right. Just for the record, before
9 we get started, yesterday's witness, Mr. Foley, was not
10 sworn in, so we came back on the record later on in the
11 afternoon and took care of that, so there is an insertion
12 in the record, and indeed throughout his testimony,
13 despite not being sworn in, he still managed to tell the
14 truth. So anyway, we will not be doing that today.
15 Going forward, witnesses will be sworn in. And
16 Mr. Kryscynski, you understand that that's going to be
17 by, be sworn in by video?

18 MR. KRYSZYNSKI: I understand.

19 JUDGE WALLACE: So yeah, when we remember
20 to do that anyway. O.K. Let's go off the record for
21 just a second.

22 (At 9:06 a.m., brief off-record discussion.)

23 JUDGE WALLACE: All right. Back on the
24 record. Ms. Hayden, please call your witness.

25 MS. HAYDEN: Your Honor, the Company
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1 calls Allen J. Kryscynski.

2 - - -

3 A L L E N J. K R Y S C Y N S K I, J R.

4 was called as a witness on behalf of DTE Electric Company
5 and, having been duly sworn to testify the truth, was
6 examined and testified as follows:

7 DIRECT EXAMINATION

8 BY MS. HAYDEN:

9 Q Mr. Kryscynski, could you please state your name and
10 business address for the record?

11 A Yes. Allen James Kryscynski, Jr., business address is
12 One Energy Plaza, Detroit, Michigan 48226.

13 Q And did you file with the Commission a document entitled
14 the Qualifications and Revised Direct Testimony of Allen
15 J. Kryscynski, consisting of a cover sheet and 102 pages
16 of questions and answers?

17 A Yes.

18 Q Do you have any changes you wish to make to your revised
19 direct testimony?

20 A No.

21 Q Is that, then, the revised direct testimony that you are
22 adopting today?

23 A Yes.

24 Q Are you sponsoring any exhibits associated with your
25 revised direct testimony?

1 A Yes.

2 Q For purposes of identification, are those direct exhibits
3 designated as Exhibit A-13 Schedules C5.6, consisting of
4 two pages; Exhibit A-23 Revised Schedule M1, consisting
5 of nine pages; Exhibit A-23 Revised Schedule M2,
6 consisting of nine pages; Exhibit A-23 Revised Schedule
7 M3, consisting of eight pages; Exhibit A-23 Schedule M8,
8 consisting of 274 pages; and Exhibit A-23 Schedule M14,
9 consisting of three pages?

10 A Yes.

11 Q Were these exhibits prepared by you or at your direction?

12 A Yes.

13 Q Do you have any changes you wish to make to those
14 exhibits?

15 A No.

16 Q Did you also file with the Commission a document titled
17 the Rebuttal Testimony of Allen J. Kryscynski, consisting
18 of a cover sheet and 73 pages of questions and answers?

19 A Yes.

20 Q Do you have any changes you wish to make to your rebuttal
21 testimony?

22 A Yes. I'm removing line 18 on page 5 through line 4 on
23 page 6 of my rebuttal testimony as a result of a motion
24 to strike.

25 Q Thank you. Is that, then, the rebuttal testimony that
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1 you are adopting today?

2 A Yes.

3 Q Are you sponsoring any exhibits associated with your
4 rebuttal testimony in this case?

5 A Yes.

6 Q For purposes of identification, are these exhibits
7 designated as Exhibit A-43 Schedule HH1, consisting of
8 one page; Exhibit A-43 Schedule HH2, consisting of 95
9 pages; Exhibit 43 Schedule HH3, consisting of 18 pages;
10 Exhibit A-43 Schedule HH4, consisting of one page and a
11 Microsoft Excel file; Exhibit A-43 Schedule HH5,
12 consisting of one page and a Microsoft Excel file; and
13 Exhibit A-43 Schedule HH6, consisting of four pages?

14 A Yes.

15 Q Were these exhibits prepared by you or at your direction?

16 A Yes.

17 Q Do you have any changes to make to those exhibits?

18 A No.

19 MS. HAYDEN: Your Honor, DTE Electric
20 moves to bind into the record the Qualifications, Revised
21 Direct Testimony, and Rebuttal Testimony of Allen J.
22 Kryscynski, and for the admission at the end of cross-
23 examination of direct Exhibit A-13 Schedule C5.6; direct
24 Exhibit A-23 Revised Schedule M1 through M3, Schedule M8
25 and M14; and rebuttal Exhibit A-43 Schedules HH1 through
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1 HH6, and tenders Mr. Kryscynski for cross.

2 JUDGE WALLACE: Thank you. Is there any
3 objection to binding in the revised direct testimony of
4 Mr. Kryscynski?

5 Hearing none, the testimony is bound in.

6 Is there any objection to binding in the
7 rebuttal, revised rebuttal testimony of Mr. Kryscynski?

8 Hearing none, the rebuttal testimony is
9 bound in.

10 (Testimony bound in.)

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STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21534

QUALIFICATIONS
AND
REVISED DIRECT TESTIMONY
OF
ALLEN J. KRYSCYNSKI

DTE ELECTRIC COMPANY
QUALIFICATIONS AND REVISED DIRECT TESTIMONY OF ALLEN J.
KRYSCYNSKI

Line
No.

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 received 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. At ITC Holdings, I worked on FERC and MISO regulatory issues
20 and represented ITC Holdings at community meetings to gain approval for new
21 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

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1 Operations (DO) investment strategy project to determine distribution grid
2 investment needs as well as work on DTE workforce projections and requirements
3 for both the Distribution Operations and Fossil Generation business units. In 2016,
4 I was appointed Manager of Distribution Operations Strategy and assumed
5 responsibility for continued work to evolve the distribution operations investment
6 strategy, operations strategy, and the chief of staff role for the Senior Vice President
7 of Distribution Operations. In early 2018, I was appointed Manager in Project
8 Management with responsibility to start up and operationalize the 4.8kV Hardening
9 Program to remove City of Detroit Arc Wire and harden the City of Detroit
10 electrical infrastructure. Later in 2018, I was appointed Manager of Tree Trim
11 Strategy where I was responsible for managing the initial Tree Trim Surge rate case,
12 Tree Trim contractor negotiations, and the overall Tree Trim strategy for
13 scheduling work, and ensuring there was an adequate supply of tree trimmers
14 necessary to complete the work. In 2020 I took over the Tree Trim Operations
15 Manager position and managed day to day Tree Trim operations including
16 overseeing all of DTE's internal arborists and foresters as well as eight tree trim
17 contractors and their 1,600+ employees. In 2022 I was appointed as Manager of
18 Distribution Operations Regulatory Strategy and Grid Modernization and promoted
19 to Acting Director in 2023.

20

21 **Q5. What are your current duties and responsibilities?**

22 A5. As Director of Distribution Operations Regulatory Strategy and Grid
23 Modernization, my current responsibilities are two primary focus areas: 1)
24 managing Distribution Operations regulatory activities – including rate cases, the
25 distribution grid plan filing, required reporting, and various Company/MPSC

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1 collaboratives, and 2) Distribution Operations long term grid modernization
2 strategy and the distribution grid plan (DGP).

3

4 **Q6. Have you previously sponsored testimony before the Michigan Public Service**
5 **Commission (MPSC or Commission)?**

6 A6. Yes. I sponsored testimony in Case No. U-21297. In addition, I supported Tree
7 Trim testimony and witnesses in U-20162, U-20561, and U-20836.

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1 **Purpose of Testimony**

2 **Q7. What is the purpose of your testimony?**

3 A7. The purpose of my testimony is to support, as reasonable and necessary, the
4 historical Operations and Maintenance (O&M) expenses related to electric
5 distribution activities for 2022 historical period and for the projected test period 12-
6 months ending December 31, 2025. Additionally, my testimony describes the (1)
7 Distribution Operations Overview which includes an introduction to the other
8 witnesses from Distribution Operations in this case and System Performance,
9 Overview, (2) Distribution Rate Request, (3) Distribution O&M, (4) Distribution
10 Grid Plan (DGP) Overview, (5) Strategic Capital Overview, (6) Overview of the
11 capital exhibits – Exhibit A-12 Schedule B5.4, and Exhibit A-23 Schedules M4,
12 M5, M6, and M7, (7) Variances between the 2022 actuals and the forecast in Case
13 No. U-21297 in Exhibit A-12 Schedule M1; projected capital expenditures
14 forecasted in Case No. U-21297 for calendar years 2023 and 2024 and the project
15 capital expenditures in this case for calendar years 2023 in Exhibit A-12 Schedule
16 M2 and 2024 in Exhibit A-12 Schedule M3, (8) Distribution Operations' Global
17 Prioritization Model (GPM) and Exhibit A-23 Schedule M14, (9) the Company's
18 Capital/Reliability Projection Model (10) Infrastructure Investment and Jobs Act
19 (IIJA) funding grants, (11) Updates on the Distribution Operation's approach to
20 Environmental Justice (EJ), and (12) Coordination Processes in place with local
21 municipalities.

22

23 I will discuss the capital exhibits and overview while the reasonableness and
24 prudence of each specific capital investments will be supported by other DO
25 witnesses.

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2 **Q8. How is your testimony organized?**

3 A8. My testimony consists of twelve parts:

4 Part I Distribution Operations Overview and System Performance

5 Part II Distribution O&M and Capital Rate Request

6 Part III Distribution O&M Overview and Exhibits

7 Part IV Distribution Grid Plan (DGP) Overview

8 Part V Strategic Capital Overview

9 Part VI Capital Exhibits Description

10 Part VII Capital Investment Variance Discussion

11 Part VIII Global Prioritization Model

12 Part IX Capital/Reliability Model

13 Part X IJA Grant Opportunities

14 Part XI Environmental Justice

15 Part XII Municipal Project Coordination

16

17 **Q9. Are you sponsoring any exhibits in this proceeding?**

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

<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
A-13	C5.6	Projected Operation and Maintenance Expenses – Distribution Expenses
A-23	M1 Revised	U-21297 2022 Forecast vs. U-21534 Comparison
A-23	M2 Revised	U-21297 2023 Forecast vs. U-21534 Comparison
A-23	M3 Revised	U-21297 2024 Forecast vs. U-21534 Comparison
A-23	M8	2023 Distribution Grid Plan, MPSC Case No.

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20147

2

A-23

M14

GPM Project and Program Rankings

3

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

5 A10. Yes, they were.

6

7 **Part I: Distribution Operations Overview and System Performance**

8 Distribution Operations Organization

9 **Q11. Can you please describe the organization that manages the investments**
10 **included in the exhibits you are sponsoring?**

11 A11. Distribution Operations (DO) is the organization that manages the investments
12 included in the exhibits I am sponsoring. The organization focuses on the design,
13 maintenance, and operation of the Company's electrical distribution system and
14 subtransmission system, which together are often referred to as "the distribution
15 system." DO is comprised of nine suborganizations, described below.

16

17 (i) Central Engineering: This organization is responsible for determining,
18 maintaining, and improving the health of the Company's electric
19 distribution assets, which includes defining technical standards for
20 distribution equipment, long-term system planning including grid
21 modernization, and developing major projects needed for customer
22 connections, relocations, increasing loads, infrastructure improvements,
23 reliability upgrades, and technology enhancements.

24

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- 1 (ii) Regulatory Strategy and Grid Modernization: This organization is
2 responsible for two primary areas of focus: 1) Distribution Operations’
3 long term grid modernization strategy and the distribution grid plan (DGP)
4 and, 2) Distribution Operations regulatory activities – including rate cases,
5 the distribution grid plan filing, MPSC required reporting, and conducting
6 and organizing the numerous collaborations ordered by the MPSC.
7
- 8 (iii) Scheduling & Construction: This organization is responsible for: 1)
9 scheduling all planned work for both DTE and contractors’ field crews on
10 overhead and underground distribution, subtransmission, and substation
11 assets; 2) leading systematic approaches to track and measure work,
12 streamlining business processes and routine tasks, and governing the
13 Maximo Business Process that coordinates team collaboration and
14 workflows across all levels of the organization; 3) planning, and field
15 oversight of out-of-state storm resources when required for large storm
16 events; 4) contractor accounts payable and invoicing, unitization of capital
17 investments, and conducting field quality inspections to validate
18 construction is built to standards and specifications; 5) governance of the
19 DO Safety, Human Performance, and Hazardous Energy Control
20 programs.
21
- 22 (iv) Operational Technology: This organization is responsible for Advanced
23 Metering Infrastructure (AMI) system enhancements and operations,
24 meter engineering and metrology, equipment calibration, grid mapping
25 including analytics, and working with business units within Distribution

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1 Operations to define, implement, and support technology and analytical
2 solutions including our Storm Excellence investments in support of our
3 storm restoration efforts. The organization also manages the Advanced
4 Distribution Management System (ADMS), which provides the
5 technological capabilities to monitor and operate the grid, respond to
6 emergency conditions and outages, and facilitates the deployment of
7 distributed energy resources.

8

9 (v) Regional Customer Operations: This organization is responsible for
10 overhead and underground emergent work, short-cycle (typically less than
11 a year) construction, new service and meter installations, and design and
12 planning focused on short-cycle reliability, and customer-requested work.

13

14 (vi) System Operation: This organization includes the Company's Electric
15 System Operations Center (ESOC), where DTE Electric monitors and
16 controls the electrical system to maintain a reliable and secure flow of
17 electric power.

18

19 (vii) Emergency Preparedness & Response "EPR": This organization plans
20 efforts to reduce the time customers spend without power and develops,
21 maintains, manages DO's incident response procedures and storm events
22 and enhances storm process for customers through improved
23 communication. EPR has expanded the organization with a pointed focus
24 on improving storm restoration processes and enhancing the Company's
25 ability to efficiently restore customers in "extreme weather" scenarios,

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1 such as recent storms our customer base has been experiencing. EPR is
2 comprised of six groups (strategy, public safety, damage assessment,
3 Regional ICS, Productivity, and Event management). The team has set
4 individual targets within each group and has initiated projects focused on
5 addressing the gaps identified from previous storms. All of this work is
6 aligned to a broad strategic plan focused on improving day to day
7 emergent operations and storm processes.

8

9 (viii) Tree Trimming: This organization plans, communicates, and implements
10 the Company's tree trimming program.

11

12 (ix) Substation Operations: This organization is responsible for the operation
13 and maintenance of all the substations within the DTE Energy service
14 territory.

15

16 **Q12. Have there been any significant changes to the DO organization since the filing**
17 **of U-21297?**

18 A12. Yes. To better support the increasing construction for grid investments, a Project
19 Management Office (PMO) was created by merging the DO project organization
20 with DTE's Major Enterprise Projects (MEP) group to consolidate project
21 management expertise in one group. This new organization is responsible for
22 management and execution of the majority of Strategic Capital projects and
23 programs for Distribution Operations, as well as large investment projects for other
24 areas of DTE. The organization consists of the project managers, cost engineers,
25 schedulers, project estimators, and the leadership/support teams required to manage

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1 and track the progress of DO's capital investments. The PMO has focus on driving
2 cost efficiency, managing project scope and schedule, and is specifically targeting
3 challenges in labor cost and availability, supply chain constraints and material
4 availability, as well as obtaining needed land, permits, and easements. Some
5 smaller programs and projects are still managed within the DO organization.

6

7 **Q13. How is the Distribution Operations testimony organized in this case?**

8 A13. Distribution Operation (DO) capital and O&M expenditures, as well as other
9 activities, are supported by six (6) witnesses in this case. Together these witnesses
10 discuss the reasonableness and prudence of DO capital and O&M expenditures,
11 exhibit content, tree trim, Environmental Justice (EJ), and other topics related to
12 DO. A high level summary of these six witnesses' scope of testimony is introduced
13 below:

- 14 1) Witness Allen J. Kryscynski is the Distribution Operations Regulatory Strategy
15 and Grid Modernization. The purpose of my testimony is described above.
- 16 2) Witness Brian Hill is the Director Southwest Regional Customer Operations and
17 Scheduling & Coordination. The purpose of witness Hill's testimony is to
18 support as reasonable and prudent the investments in base capital programs,
19 Emergent Replacements and Customer Connections, Relocations & Other.
- 20 3) Witness Morgan Elliott Andahazy is the Director of PMO Programs. The
21 purpose of witness Elliott Andahazy's testimony is to support, as reasonable and
22 prudent, investments in the strategic capital pillar Infrastructure Resilience and
23 Hardening.

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- 1 4) Witness Satvir Deol is the Director of Engineering. The purpose of witness
2 Deol's testimony is to support, as reasonable and prudent, investments in the
3 strategic capital pillar Infrastructure Redesign and Modernization.
- 4 5) Witness Shannen Hartwick is the Director of Automation for DO. The purpose
5 of witness Hartwick's testimony is to support, as reasonable and prudent,
6 investments in the Technology and Automation pillar including Grid
7 Automation, Grid Automation Telecommunication, AMI and ADMS projects,
8 and the Electric System Operations Center (ESOC) and Alternate System
9 Operations Center (ASOC) projects, and other operational technology
10 investments.
- 11 6) Witness Rachel Steudle is the Director of Tree Trim. The purpose of witness
12 Steudle's testimony is to (1) discuss the importance of and progress made in
13 DTE Electric's vegetation management ("Tree Trimming") program, (2)
14 provide details related to the Company's Tree Trimming Surge Program that
15 will deliver on the reliability goals established in the Company's Distribution
16 Grid Plan (DGP), (3) describe the customer benefits of the Company's Tree
17 Trimming Surge Program to date, (4) support the Operations and Maintenance
18 (O&M) expenses related to tree trimming efforts for the historical test period
19 ending December 31, 2022, and the projected base O&M expenses and the Tree
20 Trimming Regulatory Asset Surge funding amount for January 1, 2025, to
21 December 31, 2025, (5) request approval of incremental Surge funding for 2025,
22 (6) discuss the future of the Tree Trimming program once the Surge is
23 completed, (7) address the additional requests from U-21297.

Line
No.1 Electrical System Overview

2 **Q14. Can you briefly describe the electrical system that the Company owns and**
3 **operates?**

4 A14. The Company owns and operates approximately 31,000 miles of overhead
5 subtransmission and distribution lines, and 16,830 miles of underground
6 subtransmission and distribution lines. The Company's service territory
7 encompasses approximately 7,600 square miles and includes approximately 2.3
8 million residential, commercial, and industrial customers. Additional key statistics
9 are listed in **Tables 1 – 4.**

10

11 **Table 1 DTE Electric Substations by Type and Voltage**

Substation Type	Total Number of Substations	Number of Substations by Circuit/Low Side kV							
		4.8	8.3	13.2	4.8&13.2	24	40	24&40	Other
General Purpose	542	244	4	243	30	4	13	3	1
Single Customer	145	49	0	86	1	0	0	0	9
Customer Owned	102	NA	NA	NA	NA	NA	NA	NA	NA
Total	789	293	4	329	31	4	13	3	10

12

13 **Table 2 DTE Electric Transformers by Voltage Level**

Voltage Level	Number of Transformers	kVA Capacity
Substation - Subtransmission	178	13,085,000
Substation - Distribution	1,449	24,093,221
Distribution - Overhead and Pad-mount	451,919	33,078,863
Total	453,546	70,257,084

14

Line
No.

1

Table 3 Distribution Circuits and Line Miles

Bus Voltage	Number of Circuits	Overhead Miles			Underground			Total Miles	Total Customers
		13.2 kV	8.3 kV	4.8 kV	13.2 kV	8.3 kV	4.8 kV		
13.2 kV	1,269	11,796	16	5,596	10,710	1	417	28,535	1,030,999
8.3 kV	13	0	45	0	1	18	0	63	8,202
4.8 kV	1,991	31	0	11,064	274	0	1,937	13,307	1,213,025
Total	3,273	11,828	60	16,660	10,985	18	2,354	41,905	2,252,226

2

3

Table 4 Subtransmission Circuits and Line Miles by Substation Bus

Voltage	Number of Circuits	Overhead Miles	Underground Miles	Total Miles
120 kV	68	59	8	67
40 kV	326	2,353	466	2,819
24 kV	242	177	732	909
Total	636	2,589	1,206	3,795

4

Voltage

5

6 **Q15. What is the difference between the Company's distribution and**
7 **subtransmission voltages?**

8 A15. Voltage and purpose distinguish the difference between the Company's
9 subtransmission system and distribution system. The Company operates
10 subtransmission voltages of 24kV, 40kV, and 120kV and this infrastructure is
11 designed to feed substations that convert the voltage to distribution levels, although
12 some larger industrial customers are fed directly from subtransmission. The
13 Company currently operates distribution voltages of 4.8kV, 8.3kV, and 13.2kV and
14 this infrastructure is designed to feed the circuits that provide power to customers.

Line
No.

1

2 **Q16. How are the Company’s distribution and subtransmission voltages distributed**
3 **throughout the service territory?**

4 A16. **Figure 1** illustrates the location of the Company’s substation equipment voltages.
5 There are some substations that operate at 13.2kV but have parts of circuits that
6 operate at 4.8kV.

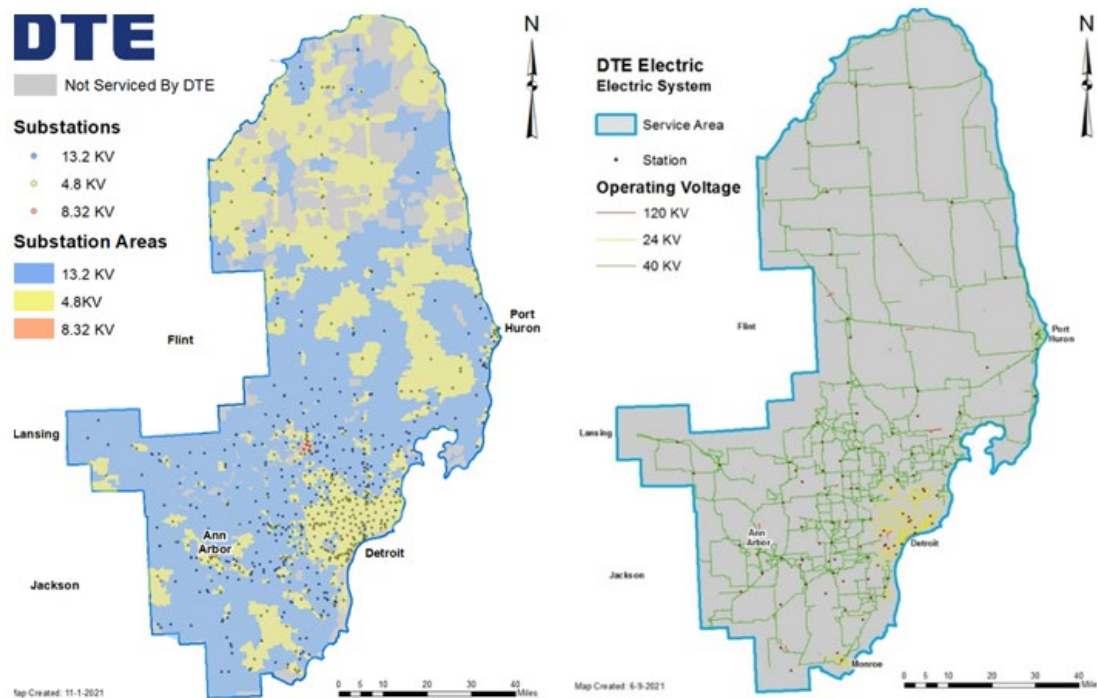
7

**Figure 1 Location of Distribution and
Subtransmission Voltages**

8

9

10



11

12 **Q17. What is the age of the Company’s distribution system assets?**

13 A17. **Table 5** provides the average age and age range of the Company’s key distribution
14 assets along with the life expectancy and demonstrates that the Company’s assets
15 are relatively aged. For some asset classes, poles for example, the average age and

Line
No.

1 the industry life expectancy of the asset are close to the same which can be an
2 indicator of challenges to current and future equipment health. While not the only
3 factor impacting reliability, age can become a significant factor when replacement
4 parts become unavailable or in the specific cases where asset health deteriorates
5 sharply with age. Eight of the 18 asset classes have an average age at or near the
6 life expectancy.

Line
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1

Table 5 Asset Age Summary

Asset (Section)	DTE Electric Age Range (Years)	DTE Electric Average Age (Years)	Life Expectancy (Years)	% of Asset Class at or Beyond End of Life
Substation Power Transformers	0-99	43	40-45	49%
Network Bank Transformers	0 – 85+	46	20 - 30	91%
Circuit Breakers	0 – 90	41	30 – 40	60%
Circuit Switchers	0 – 36	19	NA	NA
Relays	0-60+	33	15-50	NA
Switchgear	0 – 70	40	40	55%
Poles	0-90+	48	40-50	50%
Three-phase Reclosers	0-34	10	20	10%
SCADA (Supervisory Control and Data Acquisition) Pole Top Switches	0-31	15	20	38.5%
40 kV Automatic Pole Top Switches	0-50+	21	40	35%
Overhead Capacitors	Oldest: 25+	NA	20	NA
Overhead Regulators	Oldest: 25+	NA	20	NA
System Cable	0 – 100+	49	20 – 40	64%
Underground Residential Distribution (URD) Cable	0 – 60+	26	40	23.6%
Manholes	1-100+	78	Varies based on construction and field conditions	NA
Advanced Metering Infrastructure (AMI meters)	0-13	6.5	20	0%

Line
No.

1 **Q18. As shown in Table 5, how has the Company determined industry end of life**
2 **expectancy?**

3 A18. The Company's internal subject matter experts draw from a broad set of sources to
4 determine equipment life expectancy, including ongoing review of technical
5 papers, attending industry working groups, meeting with manufacturers, and
6 gaining specific experience with the performance of the assets on the Company's
7 electrical system.

8

9 **Q19. Is age the only factor to consider when selecting assets for replacement?**

10 A19. No. Age is just one of the factors considered when determining asset health and
11 the need for equipment replacement. There are instances where younger equipment
12 is at higher risk of failure, for example due to specific known equipment issues, and
13 is selected for replacement ahead of more aged equipment. Additionally, there are
14 many instances where the Company assesses older equipment and finds that it still
15 can safely and reliably remain in service and serve customers. However, age is a
16 factor used throughout industry as one measure of asset health.

17

18 System Performance

19 **Q20. How does the Company and industry measure system reliability?**

20 A20. The Company uses industry standard reliability metrics that are defined by the
21 Institute of Electrical and Electronics Engineers (IEEE) standard 1366¹. DTE
22 Electric measures overall system reliability using the indices System Average
23 Interruption Duration Index (SAIDI), System Average Interruption Frequency
24 Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI). These

¹ [Microsoft PowerPoint - Without video IEEE 1366- Reliability Indices 2-2019.pptx available at https://site.ieee.org/boston-pes/files/2019/03/IEEE-1366-Reliability-Indices-2-2019.pdf](https://site.ieee.org/boston-pes/files/2019/03/IEEE-1366-Reliability-Indices-2-2019.pdf)

Line
No.

1 indices are typically calculated in two ways: 1) All-Weather conditions, and 2)
2 excluding Major Event Days (MEDs). An MED is any 24-hour period in which
3 there is a significant statistical difference in daily SAIDI. Excluding MEDs from
4 the indices offers a more accurate comparison between time periods and to other
5 utilities because it gives the Company a clear picture of day-to-day system
6 performance and customer experience absent significant weather events – which
7 are highly variable in size, impact, and system location from year-to-year and. The
8 Company’s primary metric for measuring system reliability is the System Average
9 Interruption Duration Index (SAIDI). SAIDI is defined by IEEE as the total time
10 (in minutes) of all customer interruptions divided by the total number of customers
11 served. SAIDI measures the average time that customers are without power in a
12 year because it is calculated using both the frequency and the duration of
13 interruptions. SAIFI is calculated by dividing the number of customer interruptions
14 by the number of customers served. SAIFI measures the average number of
15 sustained interruptions experiences by the system’s average customer. CAIDI is
16 calculated by dividing the sum of customer interruption duration by the total
17 number of customer interruptions. CAIDI measures the average time required to
18 restore power to the average customer who experiences an outage.

19

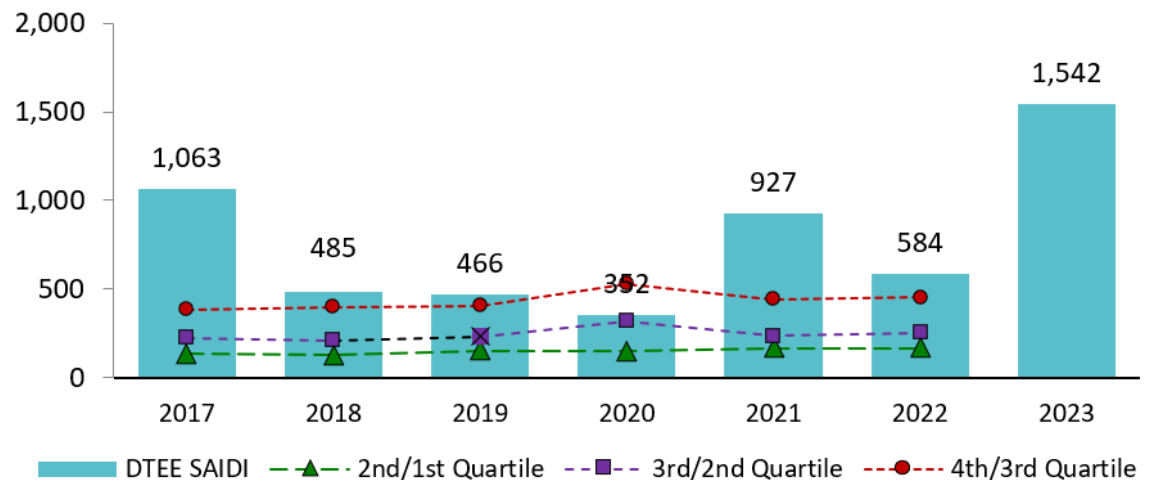
20 **Q21. What are the recent reliability metric trends for the Company’s electrical**
21 **system?**

22 A21. **Figure 2** through **Figure 5** show the distribution system performance from 2017 to
23 2023 for SAIDI-All Weather, SAIDI-Excluding MEDs, SAIFI-All Weather, and
24 SAIFI-Excluding MEDs. As shown in **Figure 2** and **Figure 3**, the Company
25 performed in the 4th quartile in All-Weather SAIDI and 3rd quartile for SAIDI-

Line
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1 Excluding MEDs for 2023. The Company has been, except for 2020, in the fourth
 2 quartile for SAIDI-All Weather for the seven years shown on **Figure 2** below. As
 3 shown in **Figure 4** and **Figure 5**, the Company performed in the 3rd quartile in All-
 4 Weather SAIFI and 2nd quartile for SAIFI-Excluding MEDs for 2023. SAIFI-All
 5 Weather has been in the second quartile four of the last seven years. Benchmarking
 6 quartiles are not yet available for 2023 so all quartiles referenced for 2023 are
 7 compared to the 2022 benchmarking numbers. CAIDI can be calculated by dividing
 8 SAIDI by SAIFI. Benchmarking is performed by the Institute of Electrical and
 9 Electronics Engineers (IEEE) and made available to its members annually.

11 **Figure 2 All Weather SAIDI Performance***
 12 **(Minutes)**



*Quartile information for 2023 is not yet available

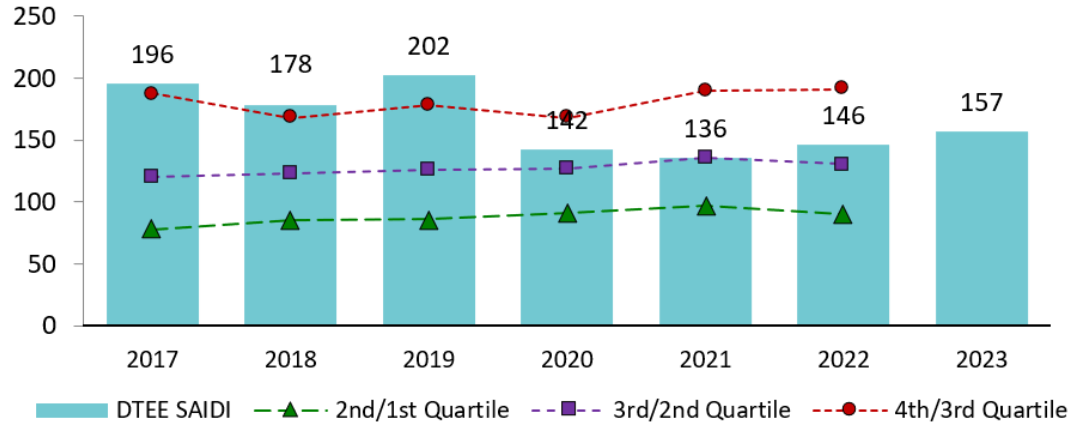
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Figure 3 SAIDI Ex-MED Performance* (Minutes)

2



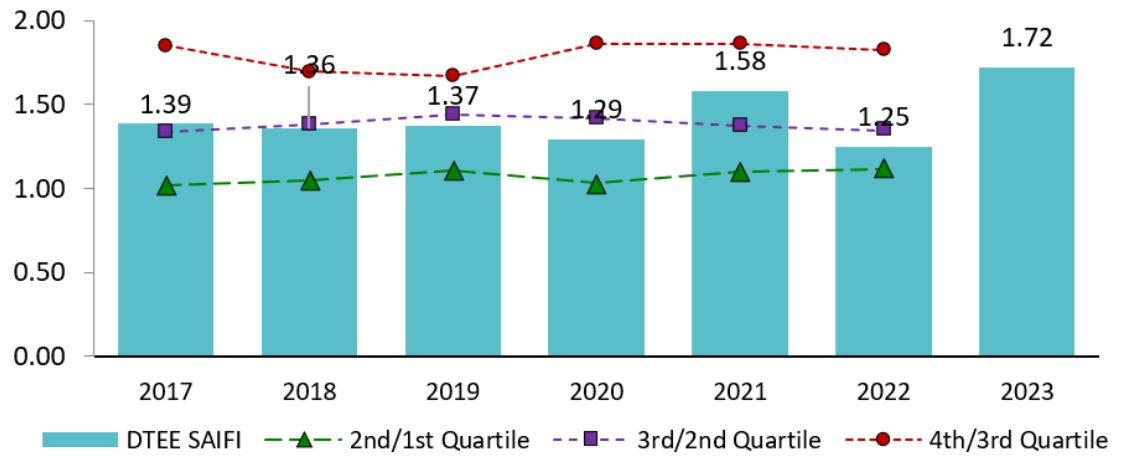
*Quartile information for 2023 is not yet available

3

4

Figure 4 All Weather SAIFI Performance*

5



*Quartile information for 2023 is not yet available

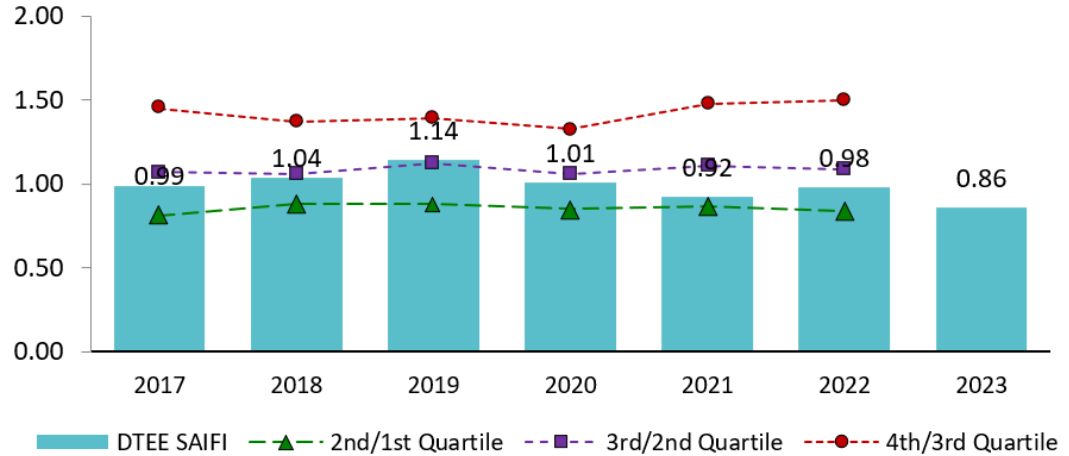
6

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1

Figure 5 SAIIFI Ex-MED Performance*

2



*Quartile information for 2023 is not yet available

3

4 **Q22. What large weather events impacted the Company’s reliability performance**
5 **in 2023?**

6 A22. This past year, 2023, brought additional large storm events including back-to-back
7 storms in February, first ice and then snow, that left over 675,000 customers
8 without power for extended periods of time. These two storms alone contributed
9 730 minutes of All-Weather SAIDI to the annual metric, more than all SAIDI
10 minutes recorded in 2022. However, if the volatility of the extreme weather is
11 removed, SAIFI and SAIDI Excluding MEDs remain in the second quartile
12 indicating that the Company’s non-storm performance is stable. See Witness Hill’s
13 testimony for additional discussion on 2023 storm impacts.

14

15 **Q23. How have previous strategic investments impacted reliability performance?**

Line
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1 A23. Positively. To name a few examples, the Company has seen improved reliability
2 results in areas that have had their Surge Tree Trim program, 4.8kV Hardening, and
3 Frequent Outage Programs. These programs and reliability improvements are
4 discussed in Witness Steudle and Witness Elliott Andahazy's testimony.

5

6 **Q24. What are the primary challenges the Company faces with respect to reliability**
7 **improvements?**

8 A24. There are three primary challenges:

- 9 • First, the Company has seen an increase in the number of high wind speed
10 days which adds additional stress to the already aged fleet of equipment and
11 provides more opportunity for failures (**Figure 6**).
- 12 • Second, the system continues to get older. The average pole age has
13 increased from 40.7 years in 2012 to 47.9 in 2024 – See **Figure 7**. Notably,
14 the slope of the line becomes less steep starting in 2022, indicating the
15 average pole age increased at a slower rate as the Company increased
16 investment in 4.8kV Hardening, PTMM, and 4.8kV Conversion. Continued
17 investments in these programs is needed in order to continue to decrease the
18 rate at which the Company's assets are aging. The pole equipment age curve
19 was selected as a representative sample of the Company's overhead
20 equipment health. DTE will continue to invest in the rebuilding the
21 overhead system to flatten and bend down the age curve.
- 22 • Third, the Company is early on its journey to stabilize and rebuild the grid.
23 While the Company has made progress to date, increased, sustained
24 investment will be needed to improve and then maintain reliability. The
25 Company's 2023 DGP provides a path forward to both improve near-term

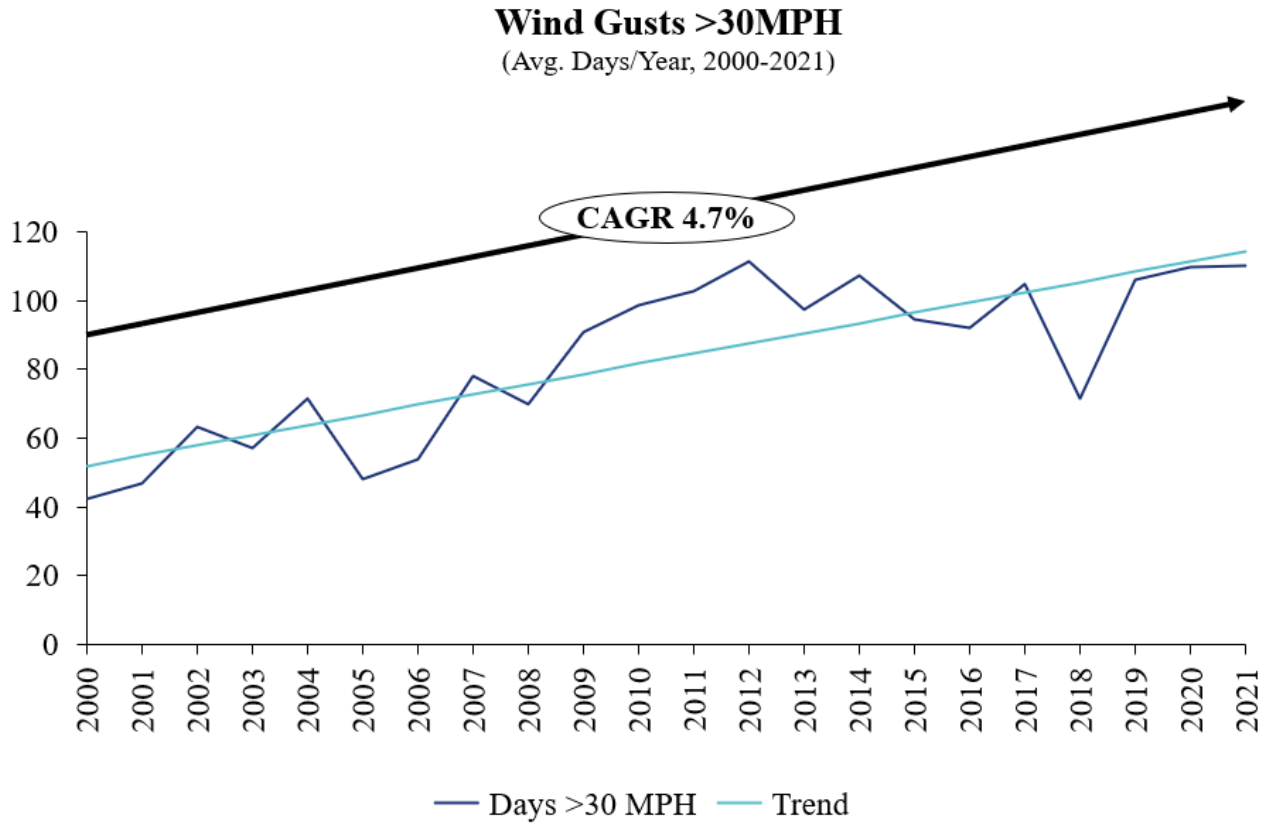
Line
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1 reliability and provides a roadmap for the required investment necessary
2 maintain long-term reliability.

3

4

Figure 6 Michigan² Wind Gusts 2000-2021



5

² Data from <https://mesonet.agron.iastate.edu/request/daily.phtml>. SE region represented by Detroit Metro, SW region represented by Ann Arbor, NW region represented by Pontiac.

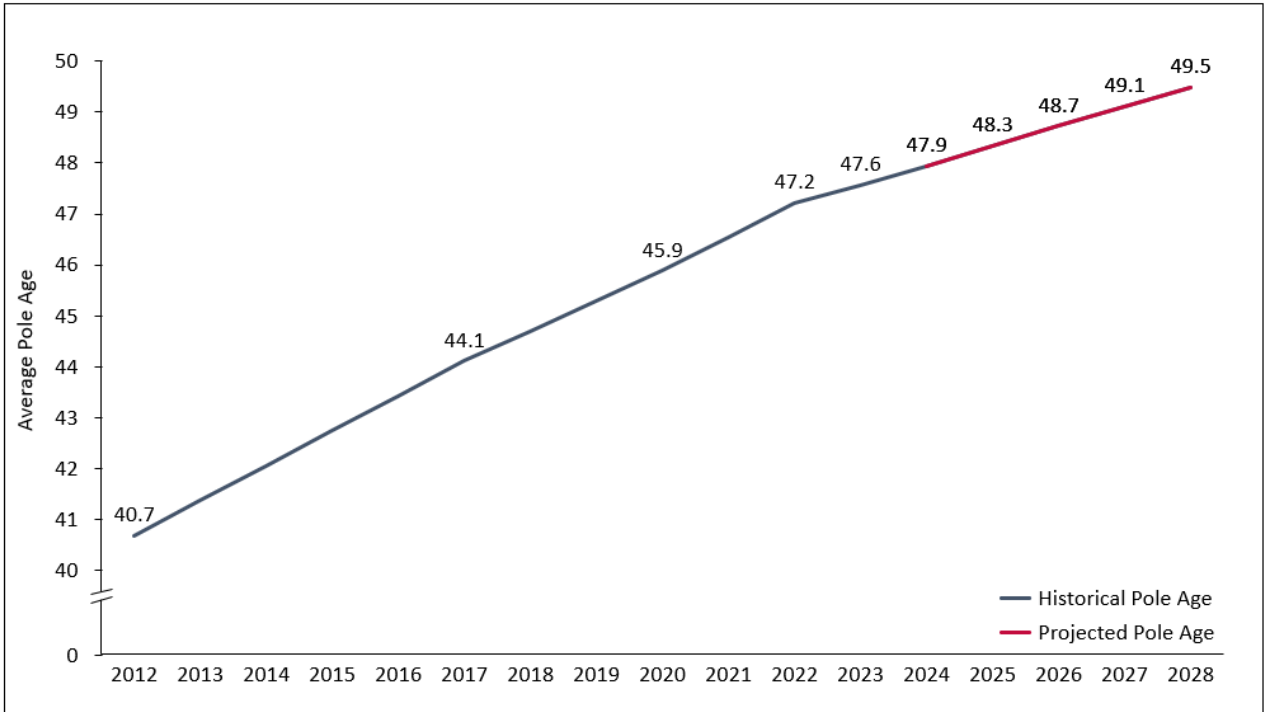
Line
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1

Figure 7 Historical and projected average pole

2

age³



3

4

5 **Q25. What changes were made to the Company’s investment strategy based on the**
6 **2023 weather events and system age and deterioration?**

7 A25. The Company has increased its investment plans in both PTMM, 4.8kV Hardening
8 and Automation in order to target near and mid-term improvements in fundamental
9 grid resiliency and restoration. Long-term work such as conversions will continue
10 to support rebuilding the grid to increase system resilience and support needed
11 capacity. The Company is also working to improve storm restoration processes,

³ Projected pole age assumes 2025-2028 strategic investment levels for PTMM, 4.8kV Hardening and 4.8kV Conversion are the same as the 2024 investments planned in the case. Poles replaced on base capital, including emergent replacements, are assumed to be constant.

Line
No.

1 including ADMS Enhancements, to be able to respond to storm events more
2 quickly.

3 **Part II: Distribution O&M and Capital Rate Request**

4 **Q26. What O&M and capital is the Company asking the Commission to include in**
5 **rates related to Distribution Operations?**

6 A26. The Company is including \$359.2 million of operation and maintenance (O&M)
7 expenses in the projected test period as shown in Exhibit A-13, Schedule C5.6, Page
8 1, Line 27.

9

10 The Company is requesting \$3.14 billion of capital investments for the 24-month
11 bridge period ending December 31, 2024 and \$1.63 billion of capital investments
12 for the 12-month projected test year ending December 31, 2025, as shown in
13 Exhibit A-12, Schedule B5.4, Page 1, Line 23, supported and sponsored by
14 witnesses Hill, Elliott Andahazy, Hartwick, Deol, and Steudle in base rates.

15

16 **Q27. Why are the levels of capital and O&M proposed by the Company necessary?**

17 A27. The levels of capital investment and O&M expense are necessary to achieve the
18 Company's goals of providing safe, reliable, and clean electricity to our customers
19 at reasonable rates. These investments also lay the foundation for grid
20 modernization, needed to support our customers' evolving needs for greater
21 resiliency in the face of increasingly frequent and intense storms, electrification
22 including electric vehicles (EVs), and the integration of distributed energy
23 resources (DERs).

24

Line
No.

1 **Part III: Distribution O&M Overview and Exhibits**

2 **Q28. What does Exhibit A-13, Schedule C5.6, “Projected Operation and**
3 **Maintenance Expenses – Distribution Expenses” show?**

4 A28. This schedule reflects the operations and maintenance costs for DO, which are
5 primarily driven by systems operations costs (including operating the System
6 Operations Center which monitors and controls the subtransmission and
7 distribution grids), addressing day-to-day trouble and storm restoration, tree
8 trimming, equipment preventative maintenance and other system maintenance
9 requirements. The expenses shown in this exhibit represent both DO and street
10 lighting. Company Witness Bellini provides testimony addressing the streetlighting
11 costs, and Company Witness Steudle supports DO’s tree trimming expenses. I am
12 supporting all other DO expenses.

13

14 **Q29. Can you provide a brief explanation of the items listed under Distribution**
15 **Expenses in Exhibit A-13, Schedule C5.6?**

16 A29. The costs associated with dispatching, coordinating restoration, and tree trim efforts
17 are included in FERC accounts 580 (Operation Supervision and Engineering) and
18 581 (Load Dispatching). Accounts 582 (Station Expenses), 583 (Overhead Line
19 Expenses), 584 (Underground Line Expenses), and 588 (Miscellaneous Expenses)
20 incorporate the costs for developing and implementing training and work force
21 planning for the Company’s substation operators and maintenance personnel,
22 apprentice lineman, splicers, technicians, engineers, riggers, and planners as well
23 as the staff groups to support these critical efforts. Job skills training is conducted
24 for the safety of employees and the public. Witness Bellini supports account 585
25 (Street Lighting and Signal System Expense). Meter testing and distribution costs

Line
No.

1 are incorporated into account 586 (Meter Expenses). Account 587 (Customer
2 Installations Expenses) includes expenses to support the specific needs of
3 customers served at primary voltages. Account 589 (Rents) reflects the expenses
4 associated with leased facilities and the Company attaching to poles not owned by
5 the Company.

6

7 **Q30. What do the line items listed under Maintenance in Exhibit A-13, Schedule**
8 **C5.6 describe?**

9 A30. Maintenance costs are critical to providing safe and reliable service. Account 591
10 (Maintenance of Structures) is to support the maintenance of existing physical
11 structures associated with the electric distribution system. Restoration,
12 troubleshooting and reactive maintenance work associated with substation,
13 overhead and underground equipment is included in accounts 592 (Maintenance of
14 Station Equipment), 593 (Maintenance of Overhead Lines), and 594 (Maintenance
15 of Underground Lines) respectively. In addition, account 593 includes the tree trim
16 expenses supported by Company Witness Steudle. The supervision and other
17 support costs for these important efforts are included in account 590 (Maintenance
18 Supervision and Engineering). Company Witness Bellini supports account 596
19 (Maintenance of Street Lighting and Signal Systems).

20

21 **Q31. How are the 2022 historical O&M and the projected test period O&M**
22 **expenses for DO shown on Exhibit A-13, Schedule C5.6?**

23 A31. Exhibit A-13, Schedule C5.6, page 1, summarizes the 12-month period ended
24 December 31, 2022 actual O&M expense and the projected O&M expense for
25 December 31, 2023 through December 31, 2025. Line 27, column (c) provides the

Line
No.

1 total actual unadjusted O&M expenses for the 12-month historical test period ended
2 December 2022.

3

4 **Q32. What are the adjustments in columns (d) and (e) of Exhibit A-13, Schedule**
5 **C5.6, page 1?**

6 A32. The adjustments in column (d) reduce the total historical test year O&M expenses
7 by the amounts related to the Transitional Reconciliation Mechanism (TRM) costs,
8 which are included in accounts 566 and 588. In column (e) the adjustment on line
9 20 is to normalize restoration expenses, see below. The total results of columns (d)
10 and (e) are added with column (c) to produce column (f).

11

12 **Q33. What are the adjustments in columns (g) through (i) of Exhibit A-13, Schedule**
13 **C5.6, page 1?**

14 A33. The adjustments in columns (g) through (i) show the inflation adjustment to convert
15 the historical test period O&M expenditures to the projected test period dollars. The
16 inflation rates for all DO exhibits are supported by Company witness Uzenski.

17

18 **Q34. What are the adjustments in column (j) of Exhibit A-13, Schedule C5.6, page**
19 **1?**

20 A34. These adjustments are one-time known and measurable adjustments to the
21 Distribution Expenses. The adjustment to Line No. 3, Operation Supervision and
22 Engineering, shows a \$1.6M increase related to the Damage Prevention Program.
23 The adjustment to Line No. 11, Miscellaneous Expenses, shows the cost for the
24 Peaker Study, \$0.3 million, that the Company agreed to complete in the IRP
25 settlement. The adjustment to Line No. 19, Maintenance of Overhead Lines – Tree

Line
No.

1 Trim, shows the \$3.4 million increase in Tree Trim base O&M to remain in line
2 with the funding levels outlined in the Tree Trim Surge plan. The adjustment in line
3 No. 20, Maintenance of Overhead Lines – Other, shows a reduction due to Tree
4 Trim Surge reduction of \$8.8 million offset by inspection expenditures of the Pole
5 and Pole Top Maintenance and Modernization (Pole/PTMM) program and the
6 4.8kV Hardening Program, an increase of \$5.0 million, a net decrease of \$3.8
7 million. The Pole/PTMM program are discussed by Company witness Elliott
8 Andahazy. The adjustment to Line No. 12 is an adjustment to the ADMS regulatory
9 asset supported by Company witness Uzenski.

10

11 **Q35. How did the Company calculate restoration O&M expense for the projected**
12 **period?**

13 A35. As shown on Exhibit A-13, Schedule C5.6, page 2, line 22, column (h), the
14 Company shows projected restoration expenses, including inflation, of \$128.2
15 million. A five-year average method was used to normalize restoration expenses
16 and is consistent with the methodology used in the Company's previous rate cases
17 and the Commission guidance in Case No. U-21297. This method addresses the
18 variability in these expenses.

19

20 The details of this calculation are shown on Exhibit A-13, Schedule C5.6, page 2,
21 "Restoration Expenses". Line 2 shows the actual expenses from 2018 to 2022
22 associated with restoration related to storm conditions. Line 10 presents the actual
23 expenses associated with non-storm restoration. Lines 3 and 11 include inflation
24 adjustments for the historical expenses, and these adjustments are included on lines
25 4 and 12 for storm and non-storm costs respectively. The expenses for the 2018 to

Line
No.

1 2022 period are averaged in column (g) and inflation is applied to those amounts to
2 determine the values in column (j). Column (h) shows the expenses included in the
3 historical test period adjusted for inflation. Column (j) shows the difference
4 between columns (h) and (i). Lines 17 to 22 summarize the calculations and shows
5 on line 22 the \$128.2 million five-year average (column (h)), the \$131.1 million
6 (column (i)) included in the historical test period and the difference of (\$2.9)
7 million (column (j)), which is the adjustment needed in the projected test period for
8 restoration costs in this case. The pre-inflation adjustment of (\$2.6) million
9 included in column (j), line 18 is carried to page 1 of Exhibit A-13, Schedule C5.6
10 in column (e), line 20.

11

12 **Q36. How was the projected O&M expense amount in column (l) of Exhibit A-13,**
13 **Schedule C5.6, page 1, derived?**

14 A36. The 12-month historical test year period ended December 31, 2022 adjusted
15 expenses from column (f) were adjusted by inflation and other expected changes in
16 column (k) to derive projected O&M costs in column (l).

17

18 **Part IV: Distribution Grid Plan (DGP) Overview**

19 **Q37. What is the role of the Distribution Grid Plan (DGP) in supporting the grid**
20 **investments included in this case?**

21 A37. Consistent with Commission guidance on the need for shorter-term investments
22 and longer-term grid planning, the Company filed the updated DGP on September
23 29, 2023, in Case No. U-20147. The 2023 DGP built on the previous DGP filed in
24 September of 2021, also Case No. U-20147 and included an update to DTE
25 Electric's distribution investment strategy considering factors including the

Line
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1 continued frequency and intensity of storms, and the aging grid assets. The 2023
2 DGP includes an increased focus on investments that will be able to quickly deliver
3 for customers a safer, more reliable, and more storm resilient grid over the next 5
4 years. In addition, the updated DGP maintains its focus on the Company's 10 to 15-
5 year vision for the grid that includes capacity needed for electrification, and
6 advances in technology to support both reliability and incorporation of Distributed
7 Generation (DG)/Distributed Storage (DS). The DGP supports the development of
8 the investments that are the basis of this case. Furthermore, the direct alignment
9 between the DGP and the investments proposed for rate base treatment illustrate
10 the Company's long-term plans and larger strategy for improving the strength of
11 the distribution system.

12

13 **Q38. Has the Company used previous versions of the DGP to support the**
14 **development of investment plans in previous rate cases?**

15 A38. In two of the Company's recent rate cases (MPSC Case Nos. U-20836, and U-
16 21297), the Company referenced the 2021 DGP filed in September of 2021. In this
17 case the 2023 DGP, along with submitted testimony, supports the Company's
18 distribution investments. The 2023 DGP is included as Exhibit A-23 Schedule M8.
19 The Company's investments as reflected in this case, and in previous cases, are
20 based on long-term distribution planning processes that identify customer and grid
21 needs and develop and prioritize projects that provide both benefits to customers in
22 terms of improved safety and reliability in the near term (primarily achieved
23 through Pole Top Maintenance and Modernization, Automation, and 4.8kV
24 Hardening), and provide the foundation for long-term changes, including increased
25 electrification and Distributed Energy Resource (DER) adoption. The investments

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1 in this case are consistent with the long-term vision laid out in the DGP filed in
2 September 2023.

3

4 **Q39. What was the Company's approach to developing the 2023 DGP?**

5 A39. To create the 2023 DGP, DTE Electric followed the five-step methodology used in
6 the development of the 2021 DGP:



7

8 • **Define DTE Objectives:** Reviewed objectives from the Company's previous
9 2021 DGP and aligned them to the long-term distribution grid vision

10 • **Assess Future Drivers of Change:** The future drivers of change that are
11 expected to have a significant impact on the distribution grid over the next five
12 to fifteen years were reviewed, including previously identified scenario
13 signposts.

14 • **Assess Current State:** Assessed the current grid and its capabilities to
15 determine how well it can support current and future customer demands.

16 • **Determine Gaps to Future State:** Identified future state objectives based on
17 future drivers of change, current state assessments and distribution grid gaps.

18 • **Develop Investment Plan:** Based on those gaps, a five-year investment plan
19 was developed, organized within the four pillars of investment. Individual
20 program and project prioritization within the investment plan is done through
21 the Company's Global Prioritization Model (GPM) process – discussed below.

22

Line
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1 Additionally, customer and stakeholder feedback were integrated into the Plan,
2 including a shift to consider environmental justice (EJ) in DTE Electric's
3 investment decisions so that projects benefiting our most vulnerable customers are
4 considered in the investment prioritization process.

5 **Q40. How did the Company gather feedback for the most recent DGP?**

6 A40. Feedback was received in several ways including:

- 7 • The March 2023 and August 2023 4.8kV Hardening and DGP Tech
8 Conferences which offered numerous stakeholders an opportunity to
9 provide feedback via roundtable discussions, questions, and written
10 comments.
- 11 • Through the regulatory process associated with Case U-21297, the company
12 received comments and feedback through MPSC Staff and stakeholder
13 testimony.
- 14 • The Commission issued Order and stakeholder comments received in Case
15 No. U-20147 containing feedback on the 2021 DGP.
- 16 • Regular engagement with the Company's customers via community
17 meetings, the DTE customer call center, MPSC complaint response, and
18 other miscellaneous forums.

19

20 **Q41. Please describe how scenario planning informs DGP investments.**

21 A41. Grid modernization plausible scenario planning involves developing scenarios that
22 are directionally correct and plausible. In the context of grid planning, plausible is
23 preferable to using the most likely scenario, in order to analyze impacts that will
24 stress or cause impacts to the grid, and therefore should be reasonably planned for.
25 Plausible scenarios provide input to grid impact of potential future challenges, as

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1 opposed to probabilistic or forecasted scenarios. These scenarios focus on a discrete
2 set of drivers and allow for a better understanding of the resulting grid impacts, as
3 well as the potential for overlapping impacts on needed capabilities and the
4 resulting determination of investments. The Company built on the work initially
5 done in the 2021 DGP, to update three scenarios to use for identifying (1) changes
6 coming to the grid in the future, (2) the grid impacts of those potential changes, and
7 (3) the investments needed to mitigate grid impacts. The three plausible future
8 scenarios selected were the Electrification scenario, the Increasing CAT storm
9 scenario, and the DG/DS Scenario (distributed generation [DG] solar photovoltaic
10 [PV] and distributed storage [DS]).

11

12 **Q42. Can you please summarize the key highlights of the DGP?**

13 A42. Using the learnings from scenario planning, combined with an assessment of the
14 current state of the grid, the Company identified gaps between the existing grid and
15 the future state required to meet the DGP objectives.

16

17 Based on this analysis, the 2023 DGP, in line with the 2021 DGP, remains focused
18 on closing these gaps through four investment pillars supporting grid improvement:

19

20 1) Tree Trimming remains focused on completing the Surge plan and returning
21 our electric grid to a routine, maintenance cycle.

22

23 2) Infrastructure Resilience and Hardening projects and programs focus on
24 making the grid more resilient in the face of increasingly severe storms,
25 replacing aging infrastructure at risk of failure, hardening the system, and

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1 addressing areas of the system with known poor customer reliability. These
2 projects and programs specifically target equipment with known risks, (e.g.,
3 failed inspections or multiple prior failures), or in areas with known poor
4 customer reliability and potential safety issues, (e.g., high SAIDI or arc wire on
5 the system). Projects in this pillar are designed to provide improved customer
6 reliability and replace at risk equipment quickly. Key areas of focus in this pillar
7 are an expansion in the PTMM program to stabilize the aging overhead
8 equipment as well as finishing the 4.8kV Hardening program which will
9 conclude in 2026 once arc wire is removed. Infrastructure Resilience and
10 Hardening investments are supported by witness Elliott Andahazy.

11

12 3) Infrastructure Redesign and Modernization projects and programs make
13 fundamental improvements to the electrical system, including the conversion of
14 the 4.8kV system and upgrades of the fundamental subtransmission system.
15 Overall redesign and modernization of the system also brings reliability and
16 resilience improvements through the replacement of aging infrastructure.
17 Investments in this pillar provide benefits such as load relief (including
18 increased capacity for electrification) and increased system operability. This
19 pillar focuses on 4.8kV Conversion to rebuild the oldest sections of the grid in
20 orders to accommodate future load growth and boost reliability. The 4.8kV
21 Conversion projects will convert the 4.8kV system to a higher voltage and be
22 built to the latest, most resilient standards, provide higher capacity for
23 electrification, enable DER penetration, and improve safety by eliminating the
24 ungrounded delta configuration and removing arc wire from the city of Detroit.
25 More detail on the 4.8kV conversion is provided is provided in Exhibit A-23

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1 Schedule M8 DGP. This pillar also includes subtransmission improvements to
2 add capacity and improve performance of this fundamental part of the grid.
3 Infrastructure Redesign and Modernization investments are supported by
4 witness Deol.

5 4) Technology and Automation projects and programs are focused on ramping up
6 the Company's automation capability and operational Technology (OT)
7 investments that will enable the Company to monitor, control, and optimize the
8 operation of grid. Investments in this pillar focus on the physical infrastructure
9 needed to support a modern distribution grid including reclosers, capacitors and
10 voltage regulation, and grid telecommunications as well as the software and
11 technology needed for operations and improved customer communication.
12 Advanced technology and automation on the grid not only improve customer
13 reliability but is also a key factor in enabling customer accessibility to the grid.
14 Additional investments include the electric system operation center (ESOC)
15 and advanced distribution monitoring system (ADMS), and develop more
16 advanced analytic capabilities. This pillar is an integral part of grid
17 modernization and will allow the Company to develop needed capabilities in
18 grid observability, analytics and computing, grid controls, and communications.
19 Investments in Technology and Automation are supported by witnesses
20 Hartwick and Steudle.

21

22 **Q43. When will the Company file a new DGP?**

23 A43. The Company expects to file another Distribution Grid Plan in 2025 on the normal
24 2-year schedule.

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1 **Part V: Strategic Capital Overview**

2 **Q44. How does the Company categorize capital investments?**

3 A44. Capital investments are broken out into two primary categories: Base Capital and
4 Strategic Capital. Base Capital programs include work the Company is required to
5 perform as part of normal business activities. There are two sub-categories of Base
6 Capital: (1) Emergent Replacements and (2) Customer Connections, Relocations &
7 Other. Emergent Replacements include expenditures to recover from interruptions
8 in electric service (e.g., emergent replacements during storms, equipment failures
9 at substations), address immediate safety concerns, or return the system to normal
10 operating conditions, and are reactive in nature. Customer Connections,
11 Relocations and Other are planned capital expenditures to address customer
12 requests for new or upgraded service connections, or to relocate equipment in
13 response to third-party requests (e.g., Michigan Department of Transportation
14 [MDOT]). Details for Base Capital programs are included in Exhibit A-12,
15 Schedule B5.4, pages 3 to 12, and in more detail on Exhibit A-23, Schedule M4,
16 and are supported by witness Hill.

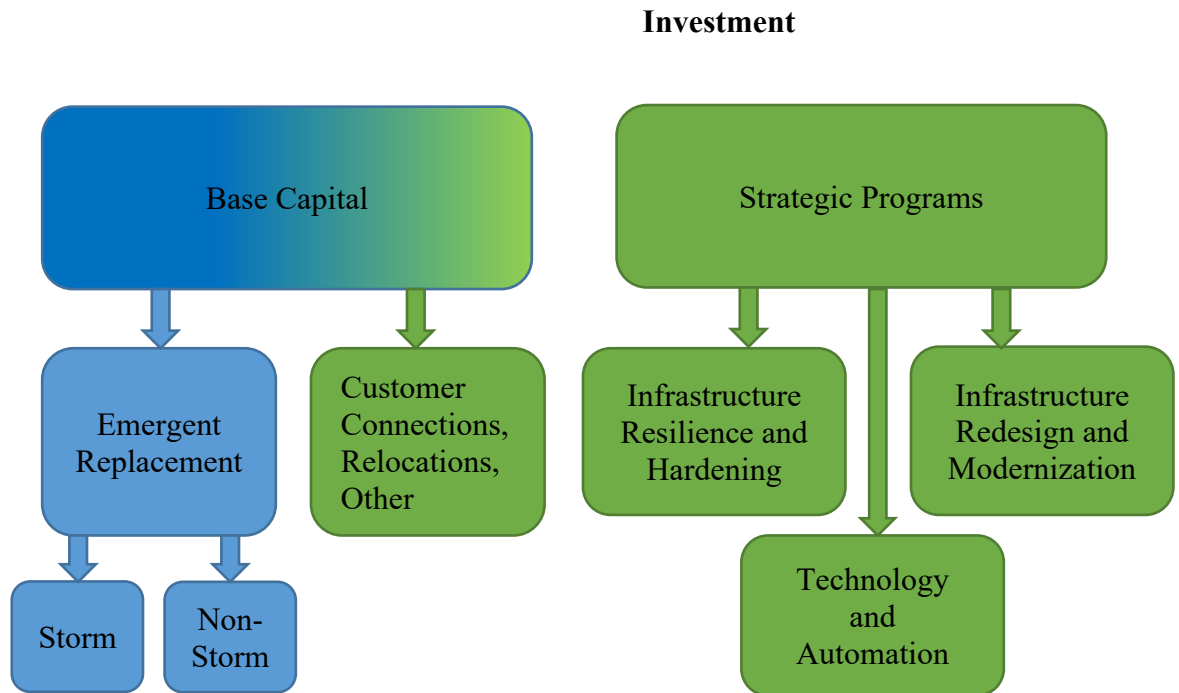
17

18 The second primary category of capital is Strategic Capital. Strategic Capital
19 projects and programs include work the Company performs to improve safety,
20 reliability and operability, and grid automation and modernization. These
21 investments are subcategorized into three areas or investment pillars: Infrastructure
22 Resilience and Hardening, Infrastructure Redesign and Modernization, and
23 Technology and Automation. Details for Strategic Capital programs are included
24 in Exhibit A-12, Schedule B5.4, pages 13 to 18, and in more detail in Exhibit A-

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1 23, Schedules M-4 through M-7, and are supported by witnesses Hill, Elliott
2 Andahazy, Hartwick, and Deol.

3 **Figure 8 Categories of Planned and Unplanned Capital**



15 *green coloring represents planned capital categories

17 **Q45. Which categories of Capital Investment is the Company able to plan for ahead**
18 **of time?**

19 A45. In **Figure 8**, the green capital categories are planned: strategic programs and
20 customer connections, relocations and other. The only category of capital for which
21 the Company cannot fully plan is emergent replacements, depicted in blue.

23 **Q46. What level of investment is the Company requesting for capital investments**
24 **that are for strategic programs or projects in the forward-looking test year**
25 **ending December 31, 2025?**

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1 A46. In the projected test year ending December 31, 2025, the Company is proposing to
2 invest a total of \$827.3 million in strategic programs and projects as part of this
3 case (Exhibit A-12 Schedule B5.4 Page 1, Line 22). Additionally, the Commission
4 approved a Distribution Infrastructure Recovery Mechanism (Distribution IRM or
5 IRM) in Case No. U-21297 totaling an additional \$290.1 million in 2025 that is not
6 included in the Company's rate request in this case (Exhibit A-33 Schedule X1
7 Page 1, Line 8) - Witness Foley provides additional information on the IRM in his
8 testimony. Summing both the proposed strategic investment for the 2025 test year
9 and the 2025 IRM yields a total of \$1,117 million of 2025 strategic investment.

10

11 **Q47. What are emergent replacements, and what level of investment is the**
12 **Company requesting for emergent replacements in the test year?**

13 A47. Emergent replacements are those necessitated by damage or failure on the system.
14 Although investments in this category are reactive, rather than proactive, they are
15 essential to restoring customers' power after an outage event, maintain system
16 operability, and in many cases increase reliability. For the projected test year
17 ending December 31, 2025, the Company forecasts \$506.9 million in emergent
18 capital (Exhibit A-12 Schedule B5.4 Page 1, Line 7). Witness Hill discusses
19 emergent replacements in detail in his testimony.

20

21 **Q48. What type of work comprises Customer Connections, Relocations and Other,**
22 **and what level of investment is the Company requesting for Customer**
23 **Connections, Relocations and Other in the test year?**

24 A48. The Customer Connections, Relocations and Other category includes multiple
25 investment areas:

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- 1 • Connections and New Load is work required to connect new customer sites
- 2 and load to the distribution system
- 3 • Relocations is work required to move DTE Electric infrastructure primarily
- 4 driven by MDOT and local road commission projects
- 5 • Electric System Equipment is an inventory of critical spare equipment to
- 6 support emergent replacements and planned projects
- 7 • Normal Retirement Unit Change-out (NRUC) and Improvement Blankets
- 8 is work focused on reducing customer outages, replacing end-of-life
- 9 equipment and supporting the AMI platform and data
- 10 • General Plant, Tools & Equipment and Miscellaneous are new replacement
- 11 tools required for field workers to perform their tasks, engineering test
- 12 equipment and substation physical security
- 13 • Public Lighting Department Project is a project to convert Public Lighting
- 14 Department customers to the Company's distribution system

15

16 The Company is requesting \$301 million in Customer Connections, Relocations
 17 and Other (Exhibit A-12 Schedule B5.4 Page 1, Lines 15 and 16). Witness Hill
 18 discusses the Customer Connections, Relocations and Other category in detail in
 19 his testimony.

20

21 **Part VI Capital Exhibits Description**

22 **Q49. How will the Company support the capital investments it is requesting in this**
 23 **case?**

24 A49. The Company is supporting the requested capital investments using witness
 25 testimony as well as five capital investment exhibits:

Line
No.

- 1 • Exhibit A-12 Schedule B5.4 Projected Capital Expenditures – Distribution
- 2 Plan (witnesses Hill, Elliott Andahazy, Deol, Hartwick and Steudle).
- 3 • Exhibit A-23 Schedule M4 Distribution Plant Capital Project Detail – Base
- 4 Capital (witness Hill).
- 5 • Exhibit A-23 Schedule M5 Distribution Plant Capital Project Detail –
- 6 Infrastructure Resilience and Hardening (witness Elliott Andahazy and Hill).
- 7 • Exhibit A-23 Schedule M6 Distribution Plant Capital Project Detail –
- 8 Infrastructure Redesign and Modernization (witness Deol).
- 9 • Exhibit A-23 Schedule M7 Distribution Plant Capital Project Detail –
- 10 Technology and Automation (witnesses Hartwick and Steudle).

11

12 **Q50. What information is included in Exhibit A-12 Schedule B5.4?**

13 A50. Exhibit A-12 Schedule B5.4 includes the total capital forecast for all of Distribution
 14 Operations categories from the historical test period, 2022, through the projected
 15 test year 12-months ending December 31, 2025, excluding investments that will be
 16 recovered through the Commission approved IRM for the 13 months ending
 17 December 31, 2024 and 12 months ending December 31, 2025. Witness Foley
 18 covers the IRM in his testimony.

19

20 Page 1 of Exhibit A-12 Schedule B5.4, column (a) includes a brief description of
 21 the expenditures included on the line, and column (b) includes the historical (2022)
 22 actual investment for each category. Between columns (a) and (b) is a list of
 23 footnotes that reference additional details for the investment and forecasting
 24 methodologies and witnesses supporting each category. Columns (c) to (e) include
 25 forecasts for each line item for 2023, 2024, and the 24-month period ending

Line
No.

1 December 31, 2024, respectively, while column (f) includes forecasts for the 12-
2 month period ending December 31, 2025, the projected test year.

3

4 Page 2 of Exhibit A-12 Schedule B5.4 provides additional detail on the information
5 provided on page 1, showing the normalization adjustments used to reconcile the
6 historical 12 months ended December 31, 2022 to the projected calendar years of
7 2023, 2024 and 2025. Page 2 is structured in much the same way as page 1 with
8 the following exceptions: columns (c) and (d) include adjustments to normalize
9 emergent replacement capital to the five-year average for use in 2024 and 2025
10 forecasts, and columns (e) to (g) provide forecasted investment for 2023, 2024 and
11 2025 respectively.

12

13 Page 3 of Exhibit A-12 Schedule B5.4 provides the calculations of the
14 normalization adjustment applied to emergent capital to reflect a historical five-
15 year average for forecasting less the emergent reduction due to strategic investment
16 and surge tree trim reduction on line 29. More detail on emergent capital
17 expenditures is provided by witness Hill, further detail on the emergent reduction
18 due to strategic investment is discussed in Part IX Capital/Reliability Model and
19 more detail regarding the surge tree trim reduction is sponsored by Witness Steudle.

20

21 Pages 4 through 9 of Exhibit A-12 Schedule B5.4 provide the three-year historical
22 average and projected investments for the Customer Connections, Relocations, and
23 Other subcategories. More detail on these capital expenditures is provided by
24 witness Hill.

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1 Pages 10 through 12 provide project lists for the historic test period for New
2 Business and Relocations and are supported by witness Hill.

3
4 Pages 13 through 18 provide the same information as pages 1 and 2 for all the
5 strategic capital projects by category and are supported by various DO witnesses as
6 shown on these pages.

7
8 Page 19 provides detail on the Allowance for Funds Used During Construction
9 (AFUDC) for DO projects and is supported by witnesses Hill, Elliott Andahazy,
10 Deol, and Hartwick. Capital investments include an AFUDC for eligible projects
11 that are in Construction Work in Progress (CWIP) as described by Witness Uzenski.
12 The total DO-related AFUDC is projected to be \$13.8 million for the 12-month
13 period ending December 31, 2025. The authorized overall rate of return used was
14 5.561% per the Order in Case No. U-21297.

15
16 Pages 20 through 26, supported by witnesses Hill, Elliott Andahazy, Deol, Steudle,
17 and Hartwick, provide a breakdown of plant activities, which are used by witness
18 Uzenski to forecast Plant in Service, Accumulated Depreciation and CWIP on the
19 projected balance sheet. Column (a) lists the project and program descriptions listed
20 in the earlier emergent, the customer connections, relocations, and other strategic
21 capital pages. Column (b) includes a corresponding in-service assumption:
22 “Annual” indicates plant investment is generally unitized within the year of
23 investment, while a specific in-service date is used for projects that remain in CWIP
24 for more than a year before moving into Plant in Service. Capital expenditures
25 consistent with page 1 are summarized in columns (c) through (f). Column (g)

Line
No.

1 includes an estimated percentage of removal costs included within the capital
2 expenditures. Removal costs, as discussed by witness Uzenski, are charged to
3 accumulated depreciation rather than Plant/ CWIP and are therefore not
4 depreciable. Removal cost of 15% based on historical trend of removals as a
5 component of capital expenditures is applied to Base Capital Programs,
6 Infrastructure Resilience and Hardening, and Infrastructure Redesign. Technology
7 and Automation projects are assigned 0% since there is no related removal work.
8 Columns (h) through (j) reflect calculated removal costs based on projected Capital
9 Expenditures in columns (d) through (f) multiplied by the removal cost percentage
10 in column (g). The remaining capital expenditures will appear in Plant in Service
11 columns (k) through (m) if the in-service assumption is “Annual”, or CWIP
12 columns (n) through (p) until the date of in-service as indicated in column (b). At
13 the time of in-service (as indicated in column (b)), cumulative investment including
14 the historical period is transferred from CWIP to in-service (excluding the removal
15 cost estimate).

16

17 **Q51. Can you describe what is included in the Exhibit A-23 Schedules M4-M7?**

18 A51. Yes. Exhibit A-23, Schedules M4-M7, supported by witnesses Hill, Elliot
19 Andahazy, Deol, Hartwick and Steudle, provide greater project detail for all
20 projects and programs included in Exhibit A-12, Schedule B5.4, and represents
21 100% of the Company’s total forecast capital for DO. Each document, which can
22 be from one to several pages, includes the following:

- 23 • Program: As described in Exhibit A-12, Schedule B5.4, pages 3 to 18
- 24 column (a).
- 25 • Purpose and Necessity: A description of the driving forces for the work.

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- 1 • Category: The pillar of Strategic Capital investment from the DGP or the
- 2 Base Capital investment.
- 3 • Line Number: A reference to the exhibits, schedule, page, and line numbers
- 4 supported.
- 5 • Scope: The scope of work.
- 6 • Benefits: How the Company’s customers benefit from the program and a
- 7 description of the how the project or program is expected to impact
- 8 operations and reliability.
- 9 • Impact Dimensions: The GPM dimensions the strategic capital project or
- 10 program will impact. Base capital is excluded from GPM scoring.
- 11 • Approximate Construction Schedule: Proposed work schedule for the rate
- 12 case period.
- 13 • Budget Basis: Origin of budget estimate.
- 14 • Total Estimated Cost: The total expected cost of the project in present
- 15 dollars – this field was added per direction from the Commission (Case No.
- 16 U-21297, p108).
- 17 • Projected: The expected cost of the program for the forecasted years 2023,
- 18 2024, and 2025 in current dollar values.

19

20 **Q52. What is included in the “Other Cost” line item shown in Exhibit A-23**
 21 **Schedules M4-M7?**

22 A52. The other cost line item represents the forecasted amount of overheads that get
 23 applied to a given project/program. Examples of project or program overheads
 24 include facilities, stock, and procurement. Facilities overhead represents the costs
 25 related to preventative maintenance, repairs, and improvements to facilities; these

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1 costs are allocated to capital projects based on the amount of direct labor. Stock
2 overhead represents the costs related to operation of warehouses; these costs are
3 allocated to capital projects based on their stock and material purchases.
4 Procurement overhead is the cost related to the supply chain procurement process;
5 these costs are allocated based on the project stock and material purchases,
6 contractor expenditures, and consultant expenditures.

7

8 “Other” costs are allocated to projects based on the mix of direct costs such as labor,
9 material usage, contractor expenditures, etc. “Other” costs for each project/program
10 can vary year to year based on the mix of direct costs. If a project has material
11 purchases scheduled for year one and the labor to install scheduled for year two, it
12 could see more overheads associated with Stock and Procurement for the first year
13 and overheads associated with Facilities in the second year. As the mix of direct
14 costs change year over year, the other costs associated will change as well.

15

16 **Part VII: Capital Investment Variance Discussion**

17 **Q53. What is the purpose of the variance analysis section of your testimony?**

18 A53. To describe variances from forecast in calendar years 2022-2024. The
19 reasonableness and prudence of these expenditures is supported primarily by
20 witnesses Hill, Elliot Andahazy, Hartwick, Deol, and Steudle in their respective
21 testimonies.

22

23 2022 U-21297 Forecast vs. U-21534 Actuals

24

25 **Q54. How does the Company’s 2022 forecast in Case No. U-21297 compare to the**
26 **actual capital investment for 2022?**

Line
No.

1 A54. Exhibit A-23 Schedule M1 Revised compares the 2022 actual capital investment to
2 the Company's capital forecast from Case No. U-21297. Overall, the Company
3 invested \$56.6 million more than forecasted in Case No. U-21297 for calendar year
4 2022, or approximately 4% above the original forecast (Exhibit A-23, Schedule M1
5 Revised, page 1, line 25). The difference is driven by lower than projected base
6 capital of \$13.2 million and increased investments in strategic capital of \$69.8
7 million. Exhibit A-23 Schedule M1 Revised, U-21297 vs. U-25134 2023 Forecast
8 Comparison, provides the project level detail of the variance.

9

10 **Q55. What are the main drivers of the decreased investment in base capital in 2022?**

11 A55. In 2022, the actual investment was \$2.8 million lower than forecast in Emergent
12 Replacements (Exhibit A-23, Schedule M1 Revised, page 1, column c, line 7) and
13 \$10.4 million lower than forecast in Customer Connections, Relocations and Other
14 (Exhibit A-23, Schedule M1 Revised, page 1, column c, line 15) and Customer
15 Advances for Construction (Exhibit A-23, Schedule M1 Revised, page 1, column
16 c, line 16). Lower investment in Emergent Replacements were driven by lower than
17 forecast equipment failure events. The lower investment in Customer Connections,
18 Relocations and Other and Customer Advances for Construction was driven by a
19 lower volume in the number of customer requests.

20

21 **Q56. What are the main drivers of the increased strategic investment in 2022?**

22 A56. In 2022, \$34.3 million of increased investment was in the Infrastructure Resilience
23 and Hardening Pillar. The Company was able to complete more units than
24 forecasted in the Pole and Pole Top Maintenance and Modernization program with
25 \$13.7 million of additional investment and \$6.2 million of additional investment in

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1 the 4.8kV Hardening program. Similarly, the Company increased its investment by
2 \$4.5 million in the Frequent Outage Program (CEMI) program by both addressing
3 more circuits and increasing scope on circuits where more work was needed for
4 reliability improvements.

5

6 The Infrastructure Redesign and Modernization Pillar had an increased investment
7 of \$10.3 million primarily driven by accelerating tree trimming work on CODI:
8 Islandview Substation ahead of circuit conversion work as well as progress
9 payments for long lead substation equipment for the 4.8 kV CC: I-94 Substation
10 and Circuit Conversion (Promenade) and System Loading: Richmond/Armada.

11

12 The Technology and Automation Pillar had increased investment of \$25.2 million.
13 The Work Management and Scheduling Upgrades project had additional
14 investment of \$6.0 million for new tools supporting field and storm processes. For
15 the Grid Automation Telecommunications as well as NWA: Omega Load Relief,
16 both projects pulled ahead \$4.4 million of material and equipment purchases to
17 avoid supply chain delays. The “Other Modernize Grid Management project” had
18 an additional \$3.0 million in investment driven by Error Free Communications
19 interface work and field network end of life equipment replacement. For the Tree
20 Trim Risk Prioritization Model, the total investment was shown in Exhibit A-12,
21 Schedule B5.7.7, page 1, line 25 in Case No. U-21297. When the project was
22 implemented, the investment was split into two locations in this case. The \$6.4 IT
23 investment shows on Exhibit A-12, Schedule B5.7.7, page 1, line 39 and \$3.1
24 million of investment shows on Exhibit A-12, Schedule B5.4, page 17, line 24. This
25 split results in a \$3.1 million increase investment in the Technology and

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1 Automation Pillar. For the Interconnection Process Enablement project, the
2 interconnection gateway platform development was pulled ahead leading to \$2.8
3 million of increased investment. An additional \$5.9 million of investment was
4 made across other projects as shown in exhibit A-23, schedule M1 Revised.

5
6 These expenditures facilitated necessary system upgrades or improvements to
7 continue safe and reliable service to customers and were reasonably and prudently
8 incurred.

9

10 **Q57. How did actual capital investments for 2022 compare to rates included in the**
11 **Commission's final Order for Case No. U-21297?**

12 A57. Distribution Operations' actual capital investments equaled \$1,496.1 million in
13 2022. In the rate order, distribution plant investments of \$1,434.3 million were
14 included in rate base, or \$61.8 million less than the actual prudently incurred
15 investments (see witness Uzenski's Exhibit A-12, Schedule B5, line 7).

16

17 2023 U-21297 Forecast vs. U-21534 Forecast

18

19 **Q58. How does the Company's 2023 forecast in MPSC Case No. U-21297 compare**
20 **to the forecast in this case?**

21 A58. Exhibit A-23 Schedule M2 Revised compares the 2023 forecast capital investment
22 Case No. U-21297 to this case. Overall, the Company is projecting to invest \$129.4
23 million more than forecasted in Case No. U-21297 for calendar year 2023,
24 approximately 9% above the original forecast. The difference is driven by higher
25 than projected base capital of \$139.9 million and lower strategic capital investments

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1 of \$10.5 million. Exhibit A-23 Schedule M2 Revised, U-21297 vs. U-25134 2023
2 Forecast Comparison, provides the project level detail of the variance.

3

4 **Q59. What are the main drivers for the 2023 base capital forecast changes?**

5 A59. The primary changes in the 2023 base capital forecast changes are driven by storms.
6 2023 included five (5) catastrophic storms, including the most damaging winter ice
7 storm in Company history, and another summer catastrophic storm event that
8 included heavy damage from historic six tornadoes. See witness Hill's testimony
9 for discussion on base capital.

10

11 **Q60. What are the main drivers for the 2023 strategic capital forecast changes?**

12 A60. For 2023, the Company is projecting \$42.4 million of increased investment in the
13 Infrastructure Resilience and Hardening Pillar, \$29.0 million of increased
14 investment in the Technology and Automation Pillar, and \$81.9 million of
15 decreased investment in the Infrastructure Redesign and Modernization Pillar.
16 Overall, the Company is forecasting \$10.5 million of decreased investment in
17 strategic capital.

18

19 2024 U-21297 Forecast vs. U-21534 Forecast

20

21 **Q61. How does the Company's 2024 forecast in MPSC Case No. U-21297 compare
22 to the forecast in this case?**

23 A61. Exhibit A-23 Schedule M3 Revised compares the 2024 forecast capital investment
24 Case No. U-21297 to this case. Overall, the Company is projecting to invest \$59.8
25 million less than forecasted in Case No. U-21297 for calendar year 2024, or
26 approximately 4% less the original forecast. The difference is driven by higher

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1 than projected base capital of \$111.0 million and lower strategic capital investments
2 of \$170.8 million. Exhibit A-23 Schedule M3 Revised, U-21297 vs. U-25134 2024
3 Forecast Comparison, provides the project level detail of the variance.

4

5 **Q62. What are the main drivers for the 2024 base capital forecast changes?**

6 A62. Emergent replacements are forecast based upon a five-year historical average as
7 discussed in Witness Hill's testimony. In this case, per the approved methodology,
8 the five-year average calculation replaced 2017, a lower cost year, with 2022, a
9 higher cost year. This change increased the projection, resulting in an additional
10 \$69.2 million in the 2024 forecast for emergent replacement (Exhibit A-23,
11 Schedule M3 Revised, column d, line 7). This increase in Emergent Replacement
12 did not impact the Company's strategic capital investment level. For Customer
13 Connections, Relocations and Other, the I-375 relocation project is a primary driver
14 of increased investment with \$25 million projected in 2024. The other cost drivers
15 that make up the full \$111.0 million are found in Exhibit A-23 Schedule M3
16 Revised, U-21297 vs. U-25134 2024 Forecast Comparison.

17

18 **Q63. What are the main drivers for the 2024 strategic capital forecast changes?**

19 A63. In Case No. U-21297 the Company forecasted total strategic capital at \$879.6
20 million for the calendar year 2024. In this case the Company is forecasting a total
21 strategic capital investment of \$708.8 million, a decrease of \$170.8 million from
22 the U-21297 forecast. Of the \$170.8 million decrease, \$60.6 million is a simple
23 shift of investment to the IRM. Project and Program investment changes were based
24 on the Company's review of strategic factors since the initial Case No. U-21297
25 filing including 2023 ice storm learnings (increased focus on near term reliability

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1 such as 4.8kV Hardening, and Automation) and the December Case No. U-21297
2 rate order. The Commission approved an annual investment level of \$659.4 million
3 in strategic investment in the Case No. U-21297 order, a difference of \$220.1
4 million from what the Company originally forecasted.

5
6 In the Infrastructure Resilience and Hardening Pillar, the Company is forecasting
7 an increase of \$56.6 million, primarily driven by an \$80.0 million increase in the
8 4.8kV Hardening program, carryover work for Substation Risk: McGraw of \$37.8
9 million, an offsetting decrease of \$57.1 million in PTMM due to rate order
10 guidance, and other miscellaneous adjustments that result in an additional \$4.1M
11 reduction. The Company is forecasting an increased investment of \$24.4 million in
12 the Technology and Automation Pillar for operational technology projects initiated
13 to support and enhance storm restoration efforts. In the Redesign and
14 Modernization Pillar, the Company is forecasting a decrease of \$251.7 driven by
15 shifting \$60.6 million of investments to the IRM and \$191.2 million of project
16 investment to later years, in part, to shift investment to projects that impact near
17 term system resiliency, including Automation and Hardening.

18

19 Capability to Execute Strategic Work

20

21 **Q64. How does the Company ensure that it has the capabilities and resources**
22 **required to make its proposed strategic investments?**

23 A64. As the long-term needs of the electric grid call for increasing levels of investment,
24 the Company has responded by increasing our labor force (employees and
25 contractors, engineering and planning staff), leveraging partnerships, and
26 strengthening project management and supply chain oversight. The Company has

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1 instituted workforce planning processes and tools that calculate overall resource
2 demands for all field trades, as well as support and enabling groups including
3 engineering, designers, and project managers. Estimates and forecasts for short-
4 term and long-term resource needs are performed on an ongoing basis as an input
5 to our sourcing decisions. DTE Electric will add staffing as needed to address our
6 growing capital investment portfolio.

7

8 The projected resources (Company and contractors) required by year-end 2023 to
9 complete the planned strategic capital investments is just over 5,200 full-time
10 equivalents (FTEs). The projected resources (Company and contractors) required
11 by year-end 2024 to complete the planned strategic capital investments is
12 approximately 5,500 FTEs. As a result, the Company currently has more line
13 workers in the field than ever before. Additionally, the Company utilizes strategic
14 partnerships with engineering and design firms and front-line labor contractors.
15 Local contractor workforce has been growing as our investments have increased.
16 Contractor needs that exceed the local workforce availability and are supplemented
17 with additional work force from outside of the area.

18

19 As discussed above, the Company has a Project Management Organization (PMO)
20 specifically focused on managing this growing work force. Additionally, the PMO
21 works with the Company Supply Chain Management team to mitigate impacts of
22 material supply chain challenges. These mitigation actions include, but are not
23 limited to:

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- 1) Increasing the number of suppliers for key equipment including transformers, insulators, and cross arms.
- 2) Demand planning with a long-time horizon, including securing product slots for current year and beyond with suppliers.
- 3) Deploying weekly and daily tracking calls with key suppliers (driving collaboration and leveraging our resources, including transportation, to keep orders on track).
- 4) Sending supply chain and other employees to supplier facilities to provide real time governance and quality control on purchased materials.

10

11 The Company continues to grow its strategic capital capabilities with over \$700
12 million invested in 2022 and over \$800M invested in 2023.

13

14 **Part VIII: Global Prioritization Model**

15 **Q65. What is the Global Prioritization Model (GPM) and how does it support the**
16 **prioritization of capital strategic investments?**

17 A65. The GPM is a tool the Company's Distribution Operations team developed to
18 prioritize investments by ranking projects and programs based on the benefits the
19 project or program delivers for a given level of investment. The ranking is
20 accomplished through a process of evaluating a project across ten impact
21 dimensions, which represent project benefits, and developing a total project score
22 based on the weighting of each impact dimensions. The model results serve as the
23 initial basis for the Company's investment prioritization and highlight those
24 projects that have the highest relative benefit and/or are most urgent.

25

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1 **Q66. Does the GPM consider benefits and costs?**

2 A66. Yes. Each of the ten impact dimensions within the GPM measures a benefit of the
3 project or program. These benefits are weighed against costs in eight of the
4 dimensions. Costs are not considered when evaluating if the project or program
5 delivers benefits in the “Regulatory Compliance” or “Investment in EJ
6 communities” dimensions.

7

8 **Q67. Does the GPM determine if benefits exceed costs?**

9 A67. No. In order to determine if benefits exceed costs, all benefits would need to be
10 translated into a monetary value. Only two of the benefits the GPM captures, O&M
11 Avoidance and Capital Avoidance, are measured in monetary terms. All other
12 dimensions are quantified in non-monetary terms. While the GPM does not
13 determine if benefits exceed costs, it does utilize benefit-cost ratios in most of its
14 dimensions to provide a result where projects which deliver the most benefits per
15 dollar invested receive the highest scores. Not all dimensions use this structure,
16 specifically “Regulatory Compliance” and “Investment in EJ Communities”, where
17 programs receive a score without dividing by overall project cost.

18

19 **Q68. Why doesn't the Company convert all project benefits to a monetary value?**

20 A68. The non-monetary benefits which the GPM measures have no standard or generally
21 accepted method available to convert the quantified benefits into a monetary value.
22 While SAIDI and SAIFI can be monetized relative to the customer potential cost
23 impacts of an outage by using the ICE calculator developed by Lawrence Berkeley
24 National Laboratory (LBNL), that methodology has limitations including dated
25 customer survey data. Other benefits such as providing load relief so that equipment

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1 does not operate over its designed rating, or reducing the probability of major
2 events, or investing in EJ communities do not have any commonly accepted
3 conversion to a monetary value. Additionally, the Company does not place a
4 monetary value on project benefits which deliver safety benefits such as a reduction
5 in energized wire-downs. Using the Current GPM methodology, the Company can
6 transparently demonstrate which projects provide the highest benefit for customers
7 across different impact dimensions.

8

9 **Q69. What determines whether a project is scored in the GPM?**

10 A69. The engineering team evaluates alternatives to meet the system needs and selects
11 the best project or program to move forward. If necessary, a BCA takes place as
12 part of the engineering process to select the best option. The solution which is
13 selected to move forward is scored in the GPM for prioritization.

14

15 **Q70. Has the GPM model been recently updated?**

16 A70. Yes. As introduced in the 2023 DGP filing the GPM has been updated to include
17 three new dimensions to capture additional project benefits and to align to two
18 additional planning objectives (Clean, and Customer Accessibility and Community
19 Focus). Specifically, the dimension of “Investment in EJ communities” was added
20 based on feedback from the Commission to incorporate equity into the decision-
21 making process.⁴ Additionally, the weightings of each dimension have been
22 updated. The “Investment in EJ communities” addresses the Commission’s order
23 in Case No. U-20836: “the Commission will continue to hold DTE Electric to its

⁴ See Commission’s Order on November 18, 2022 in docket U-20836 (p 459).

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1 commitments to more fully incorporate equity considerations into its decision-
2 making processes”.

3 **Q71. How does the GPM consider DTE Electric's planning objectives when**
4 **evaluating the Company's distribution investment options?**

5 A71. The Company uses the GPM to assess the benefits that strategic investments have
6 on the distribution system as they relate to each of five planning objectives of 1)
7 Safe, 2) Reliable and Resilient, 3) Affordable, 4) Clean, and 5) Customer
8 Accessibility and Community Focus. All impact dimensions that are measured in
9 the GPM are aligned to one or more of these five planning objectives as described
10 in **Table 6**. These five objectives also align with the Commission’s overarching
11 objectives for the electric distribution system, which are safety, reliability and
12 resilience, cost effectiveness and affordability, and accessibility.⁵

13

14 **Table 6 Mapping of GPM impact dimensions to Planning Objectives**

15

		Planning Objectives				
		Safe	Reliable and Resilient	Affordable	Clean	Customer accessible and community focus
GPM Impact Dimensions	Reduce Electrical Hazards	✓		✓		
	Overload Relief	✓	✓	✓	✓	✓
	SAIDI	✓	✓	✓		
	SAIFI		✓			
	Regulatory Compliance	✓	✓			
	Major event risk	✓	✓	✓		
	Capacity Relief		✓		✓	✓
	Investment in EJ communities					✓
	O&M Avoidance			✓		
	Capital Avoidance			✓		

16

⁵ 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-20147 (pp 36-38).

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1 **Q72. What impact dimensions are quantitatively assessed to determine project and**
2 **program impact across the Company’s Planning Objectives?**

3 A72. In the GPM, strategic investments are evaluated against ten impact dimensions as
4 described in **Table 7**. Quantitative assessments are conducted for all the impact
5 dimensions to score and rank investments.

6

7 **Q73. What impact dimensions have remained unchanged in the updated GPM?**

8 A73. Six of the Seven original impact dimension have calculations that remain
9 unchanged. Four impact dimensions, Regulatory Compliance, Major event risk,
10 O&M Avoidance, and Capital Avoidance, are unchanged from the previous GPM.
11 Two additional dimensions have been renamed but the calculations are the same as
12 in the previous GPM. The “Reduce electrical hazards” dimension was previously
13 named “Safety” and “SAIDI” was previously named “Reliability”.

14

15 **Q74. What impact dimensions were added or changed in the updated version of the**
16 **GPM?**

17 A74. Two dimensions were added, and one dimension was divided into two separate
18 dimensions. The two new dimensions are “SAIFI” and “Investment in EJ
19 communities”. To better differentiate day-to-day loading challenges from
20 constraints that limit operational flexibility, the “Load Relief” dimension in the
21 previous iteration of the GPM has been split into two dimensions: “Overload Relief”
22 and “Capacity Relief”.

23

24 **Q75. Was the weighting of dimensions changed in the updated version of the GPM?**

Line
No.

- 1 A75. Yes, the weighting of the dimensions was simplified from a ten-point scale to a
2 three-point scale.

3 **Table 7 Global Prioritization Model Impact Dimensions**

4

Impact Dimension	Drivers	Weight
Reduce Electrical Hazards	<ul style="list-style-type: none"> Reduction in wire down events Reduction in secondary network cable manhole events 	3
Overload Relief	<ul style="list-style-type: none"> Elimination of overloaded equipment 	
SAIDI	<ul style="list-style-type: none"> Reduction in duration of outage events 	
SAIFI	<ul style="list-style-type: none"> Reduction in frequency of outage events 	
Regulatory Compliance	<ul style="list-style-type: none"> MPSC staff's recommendation (March 30, 2010, report) on utilities' pole inspection program Docket U-12270 – Service restoration under normal conditions within 8 hours Docket U-12270 – Service restoration under catastrophic conditions within 60 hours Docket U-12270 – Service restoration under all conditions within 36 hours Docket U-12270 – Same circuit repetitive interruption of fewer than five within a 12-month period 	2
Major Event Risk	<ul style="list-style-type: none"> Reduction in extensive substation outage events that lead to a large amount of stranded load for more than 24 hours 	
Capacity Relief	<ul style="list-style-type: none"> Elimination of system capacity constraints 	
Investment in EJ Communities	<ul style="list-style-type: none"> Percent of customers impacted by investment in EJ communities 	
O&M Avoidance	<ul style="list-style-type: none"> Trouble event reduction and truck roll reduction Preventive maintenance investment reduction 	1
Capital Avoidance	<ul style="list-style-type: none"> Trouble event reduction and truck roll reduction Reduction in capital replacement either during equipment failures or avoided planned capital work 	

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1 **Q76. What are the drivers of the changes to the GPM?**

2 A76. The GPM was changed to capture customer benefits that were not previously
3 accounted for, and to include benefits from across all of DTE Electric’s Planning
4 Objectives (as shown in **Table 6**). “SAIFI” was added because reducing frequency
5 of outages is important to providing reliable power to our customers, and because
6 the State’s Reliability and Service Quality standards provide guidance on what
7 outage frequency is consistent with an acceptable level of service. Project benefits
8 in the “Capacity Relief” dimension were added to measure projected load
9 constraints in 2035, and to account for benefits accrued by addressing circuits that
10 do not have enough capacity to fully realize automation capabilities. Incorporating
11 the 2035 load projection aligns with the Company’s goals to provide a grid that
12 facilitates a transition to a decarbonized economy. “Overload Relief” accounts for
13 benefits that come from reduced day-to-day equipment loading. Finally, by adding
14 the “Investment in EJ communities” dimension, which scores a project based on
15 the percentage of customers benefiting from this project who are from EJ
16 communities, we have incorporated equity into our planning and capital
17 prioritization process as directed by the Commission in 2022.⁶

18

19 **Q77. How are projects ranked using the GPM?**

20 A77. Strategic investments are assessed, scored, and then ranked in a quantitative manner
21 on how they support/improve each impact dimension. **Table 8** shows the mapping
22 of the investments to the impact dimensions they general receive a score in, based
23 on the benefits the investment delivers.

24

⁶ See Commission’s Order on November 18, 2022 in docket U-20836 (p 459).

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Table 8 Selected programs and GPM impact dimensions

Program	Impact Dimensions									
	Reduce Electrical Hazards	Overload Relief	SAIDI	SAIFI	Regulatory Compliance	Major Event Risk	Capacity Relief	Investment in EJ Communities	O&M Avoidance	Capital Avoidance
Substation Risk						X		*		
4.8kV Hardening	X		X	X				X	X	X
PTMM	X		X	X	X			P	X	X
Cable Replacement						X		P		X
Frequent Outage			X	X	X			P		
Breaker Replacement			X	X		X		P	X	X
URD Replacement			X	X				P		X
Subtransmission Redesign		X					X	*		
CODI	X	X	X	X		X		*	X	X
4.8kV Conversion	X	X	X	X		X		*	X	X
System Loading		X	X	X		X	X	*	X	X
Automation	X		X	X				P		

Investment in EJ Community Key: * = Dependent on location of project, X = Yes, addresses EJ communities, P = program where some areas of the program will occur in EJ communities

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Detailed analyses based on historical data, engineering assessments, and field feedback was 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 used to determine the relative difference between projects.

Unit measurements used for benefit-cost ratios are different for each impact dimension. For example, reliability benefits are captured in customer minutes of interruption reduction whereas O&M and reactive capital benefits are captured in dollars avoided.

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1 Each program's benefit-cost score for each impact dimension is indexed so that a
2 project with a benefit-cost ratio at the 95th percentile receives a score of 100.
3 Projects scoring exceptionally high, above the 95th percentile, will receive a score
4 above 100. This method provides three benefits. First, by aligning the 95th
5 percentile to a score of 100, outlier projects do not skew the entire index. Second,
6 the 100-point scale makes it makes it easy to understand which projects are
7 delivering the highest benefit per dollar invested – namely, the ones which score
8 closer to 100. Finally, indexing, along with the weighting of dimensions, allows for
9 the consideration of multiple monetary and non-monetary benefits to be combined
10 into a single analysis.

11

12 Impact dimensions are weighted relative to each other. **Table 7** lists the different
13 weights given to each impact dimension. The weights of each dimension were
14 simplified in the recent GPM update from a 10 point range to a 3 point range
15 Dimensions which align with core safety and reliability improvements, such as
16 Reduce Electric Hazards, one of the Company's most important impact dimensions,
17 is given the highest weight of 3. This change effectively means that a score of 100
18 in a lower weighted dimension will not be worth as much as a 100 rating in Reduce
19 Electrical Hazards. For example, if a project's Reduce Electrical Hazards score is
20 50 (on a 0-100 scale), it will be multiplied by a weighting factor of 3 to receive a
21 score of 150. A project with a Capacity Expansion score of 50 will be multiplied
22 by the weighting of 2 and contribute 100 to the total scoring. This example
23 illustrates how the impact dimension weights will rank projects higher if they
24 provide benefits in dimensions which have higher weightings. Once a program's
25 index scores have been calculated across all impact dimensions and adjusted by

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1 weighting, the index scores are summed together to determine the program's
2 overall score. The higher the score, the better the GPM ranking.

3

4 **Q78. How do the GPM results influence the Company's distribution investment**
5 **decisions?**

6 A78. We use the GPM to pick the highest relative benefit projects that will have the
7 greatest impact improving the grid and the overall customer experience. Projects
8 and programs are ranked using the GPM on an annual basis. Investments that score
9 highest in the GPM rankings are generally selected for the Company's distribution
10 infrastructure strategic investment plan. As described in detail below, there are
11 some projects that are chosen outside of the GPM process or lower ranked projects
12 within the process that are funded for various operational reasons.

13

14 Projects and programs that span multiple years are evaluated every year and may
15 experience a change in GPM ranking if additional information changes the expected
16 project costs or benefits. However, to keep scoring relatively consistent year over
17 year, the entire project cost and entire project benefits are still used when scoring
18 the project or program – although the project costs and benefits will be adjusted for
19 known changes (examples include costs increases or more benefits than forecast).

20

21 **Q79. How does the GPM support reasonable and prudent prioritization of**
22 **investments?**

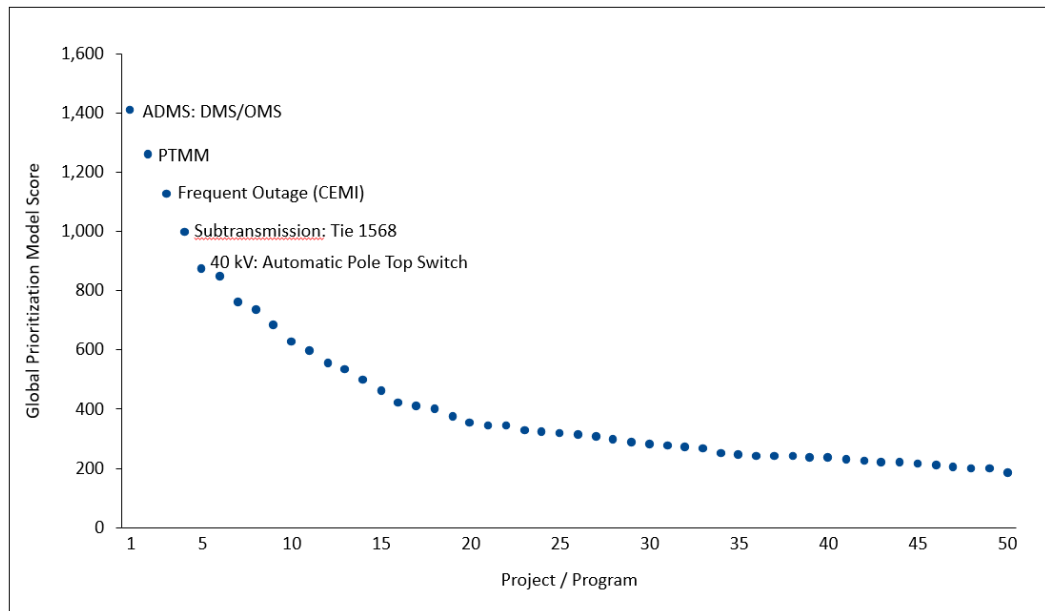
23 A79. The GPM helps the Company compare hundreds of vastly different types of
24 projects and programs of different sizes and identify which ones are going to be the
25 most beneficial for customers.

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1 **Q80. What are the GPM scores for the projects and programs proposed in this case?**

2 A80. The total GPM scores for strategic capital projects and programs, ranked from
3 highest to lowest, is illustrated in **Figure 9**. **Table 9** lists the names of the capital
4 projects and programs ranked in the top 50. GPM scores for the top 50 projects and
5 programs including scores for each of the 10 impact dimensions is included in
6 Exhibit A-23 M14 GPM Project and Program Rankings. Tree trimming⁷ to the
7 enhanced specification, although excluded from the **Table 9** and **Figure 9**,
8 continues to provide high customer benefits, and ranks within the top five projects
9 and programs in the Company’s five-year investment portfolio.

10 **Figure 9 Overall Benefit-Cost Scores for top 50 strategic capital**
11 **programs and projects**



12

⁷ Tree trimming, as an O&M program, is excluded from the **Figure 9** and **Table 9**. Nonetheless, tree trimming to the enhanced specification has a top 5 benefit-cost ranking among all programs.

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Table 9 Top 50 Strategic Capital Programs and Projects Based on GPM

Rank	Capital Program/Project	Rank	Capital Program/Project
1	ADMS: DMS/OMS	26	CODI: Targeted Network Secondary Cable Replacement
2	Pole and Pole Top Maintenance and Modernization (PTMM)	27	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)
3	Frequent Outage Program (CEMI)	28	Substation Risk: Chestnut
4	Subtransmission Redesign & Rebuild: Tie 1568	29	Cable Replacement Program
5	40 kV: Automatic Pole Top Switch	30	Subtransmission Redesign & Rebuild: Trunk
6	4.8 kV CC: Hawthorne Relief and Circuit Conversion	31	CODI: Islandview Substation
7	4.8 kV Hardening	32	Subtransmission Redesign & Rebuild: Tie 3416 Reconductoring
8	CODI: Charlotte Network Upgrade	33	Subtransmission Redesign & Rebuild: Bernard
9	Distribution Automation	34	CODI: Kent/Gibson Conversion
10	Subtransmission Redesign & Rebuild: Trunk 2237-ST	35	Subtransmission Redesign & Rebuild: Trunk 7386
11	CODI: Garfield Network Upgrade	36	URD Replacement Program
12	Subtransmission Redesign & Rebuild: Trunk 7105	37	Subtransmission Redesign & Rebuild: Trunk 7333
13	Substation Risk: Savage	38	CODI: Alfred Substation Expansion
14	Subtransmission Redesign & Rebuild: Trunk 7106	39	Subtransmission Redesign & Rebuild: Trunk 4217
15	4.8 kV CC: ISO Conversion Program	40	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion
16	4.8 kV CC: Zenon Circuit Conversion Phase 2	41	Subtransmission Redesign & Rebuild: Trunk
17	Subtransmission Redesign & Rebuild: Trunk 2419	42	Subtransmission Redesign & Rebuild: Hurst
18	CODI: Howard Conversion	43	4.8 kV CC: Cortland / Oakman / Linwood Consolidation
19	4.8 kV CC: McKinstry Sub Decommission	44	Subtransmission Redesign & Rebuild: Tie 6907
20	Substation Risk: Port Huron	45	Subtransmission Redesign & Rebuild: Cortland Station Expansion
21	8.3 kV CC: Pontiac Overhead/Underground Conversion	46	Breaker Replacement Program
22	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion	47	Substation Risk: McGraw
23	Subtransmission Redesign & Rebuild: Trunk 2255	48	4.8 kV CC: Belleville Substation and Circuit Conversion
24	4.8kV CC: Barber Substation and Circuit Conversion	49	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker
25	Subtransmission Redesign & Rebuild - Trunk 2448	50	Subtransmission Redesign & Rebuild: Waterman

3

4 **Q81. Are there other factors besides the GPM ranking that determine final timing**
5 **of program and project selection?**

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1 A81. Yes. While the benefit-cost scores of programs and projects and their prioritization
2 ranking provide the foundation for the Company's strategic investment decisions,
3 there are other considerations that impact project selection and timing, as listed
4 below:

5

6 • Investment timing 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 project
11 sequencing decisions are made. Funding decisions also consider the
12 Company's capacity to perform the work, as the Company often partners
13 with third parties to plan and execute projects.

14 • System operational constraints and stability, occasionally including
15 transmission, can cause the Company to pull a project ahead. For example,
16 a project may be needed to address subtransmission system integrity caused
17 by load growth.

18 • Regulatory requirements or guidance also influence the selection of some
19 projects and programs regardless of the GPM ranking. NERC requirements,
20 for example, require upgrades to ensure the bulk electric system is
21 unaffected by subtransmission outages. These NERC driven projects have
22 benefits that are difficult to quantify in GPM.

23 • Safety issues that cannot be easily quantified and indexed could warrant an
24 investment outside of the GPM model to protect our customers or

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- 1 employees. For instance, subtransmission disconnect switches and the
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,
6 the pilots help provide the data for a more adequate accounting of future
7 project benefits. An example is non-wire alternative (NWA) projects. These
8 NWA pilot projects focus on using alternative technologies to address circuit
9 or substation overload concerns to help delay or offset traditional grid
10 upgrades. The Company developed these NWA pilots to better understand
11 the customer and costs benefits as part of the longer-term grid modernization
12 plan, so that in the future these can be evaluated against more traditional
13 alternatives. These pilots are supported by Company witness Hartwick and
14 detail is provided in Exhibit A-12 Schedule B5.4.1 through B5.4.7 and
15 B5.4.9.
 - 16 • Capital projects are subject to development milestones, especially in the
17 conceptual design and early development stages, including land availability
18 and property purchases, municipal approvals and construction permits, right-
19 of-way acquisition and easements, and lead times when procuring major
20 equipment. While the Company takes proactive measures to mitigate these
21 execution risks, many of these early-stage milestones are difficult for the
22 Company to control and can introduce schedule delays or cost increases.
23 Therefore, the Company's investment and maintenance plan is designed to
24 include some flexibility to accommodate these unpredictable variations in
25 timing and cost.

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- 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 IJJA grants, it could positively impact project
7 selection due to grant project completion requirements. In 2023, the
8 Company was awarded an Adaptive Networked Microgrids (ANMs) grant
9 which the Company has funded in both 2024 and 2025. This project is further
10 discussed by witness Hartwick.
- 11 • Projects already in active construction.
- 12 • Some Operational Technology (OT) projects are not evaluated through the
13 GPM, as the GPM is designed for investments which upgrade the physical
14 distribution grid. The specific benefits which OT projects deliver are
15 discussed in more detail in witness Hartwick's testimony.

16

17 It is important to note that some programs and projects may not receive funding in
18 a particular year due to lower benefit-cost scores relative to other projects, but this
19 does not indicate that these programs or projects are not beneficial to customers, or
20 that they will not be selected in other years. Rather, all the programs and projects
21 identified by the Company and evaluated by the GPM provide system
22 improvements and may be funded at some point over the next several years. While
23 the strategic capital investment plan is primarily driven by the GPM, the Company
24 may adjust the annual plans based on changing circumstances and grid needs.

25

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1 **Q82. Do the GPM scores and rankings have the potential to change over time?**

2 A82. Yes. As the Company continues to make investments in distribution infrastructure,
3 the effectiveness of the capital investment is examined on a regular basis. The
4 benefit-cost scores of the programs and projects may change over time as new data
5 becomes available. The prioritization ranking of the programs and projects may
6 change accordingly.

7

8 **Part IX: Capital/Reliability Model**

9 **Q83. Based on DO investments requested in this case, what system reliability**
10 **improvements are expected?**

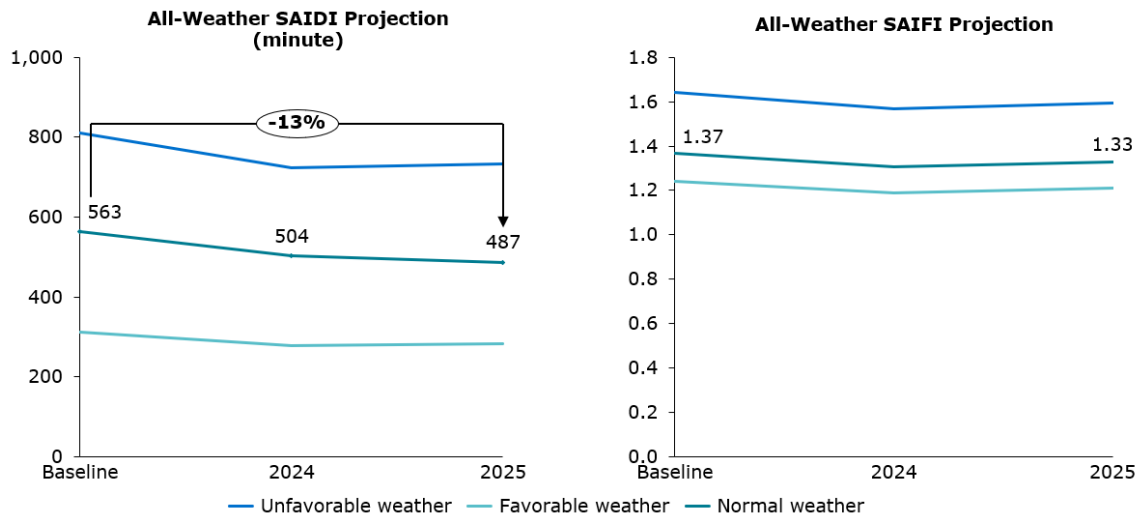
11 A83. The Company's reliability model projects that customers will experience an all-
12 weather SAIDI of 504 minutes in 2024 and 487 minutes in 2025 versus a historical
13 baseline of 563 minutes, assuming normal weather. Similarly, all weather SAIFI
14 will improve to 1.33 in 2025 from the historical baseline of 1.37. The model
15 assumes that due to timing of the execution of projects and programs, half of the
16 benefits are realized in the year of construction and full benefits are realized the
17 following calendar year. Graphs of expected reliability improvements are shown in
18 **Figure 10.**

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Figure 10

All-Weather Reliability Projections



2

3 **Q84. How does the Company calculate its reliability projections?**

4 A84. The reliability calculations are performed at a circuit level based on historical
5 performance and the impact of planned investments on those circuits. The projected
6 performance of all circuits is summed to provide a system level projection. The
7 process to project reliability performance within the model can be summarized in
8 five steps:

- 9 ○ **Baseline:** Calculate circuit-level baseline reliability performance
- 10 ○ **Program impact:** Estimate impact of reliability programs
- 11 ○ **Degradation impact:** Estimate impact of system degradation
- 12 ○ **Investment plan:** Enter planned or expected in-service schedule for
13 reliability programs into model
- 14 ○ **Calculate Ex-MED performance:** Combine baseline performance with
15 investment plan on a circuit level to project future performance
- 16 ○ **Calculate All-weather performance:** Scale Ex-MED output to all weather
17 output and expected ranges

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1 Each of these steps is described briefly below.

2

3 **Q85. How is the starting point, or circuit baseline calculated?**

4 A85. Each circuit has a baseline of reliability performance based on five years of
5 historical, non-MED event volume. Events are further divided into tree and non-
6 tree, single and multiple, and outage and non-outage events. An average customer's
7 interrupted (CI) and customer minutes interrupted (CMI) per event is used to
8 convert the volume of events to a SAIDI Ex-MED and SAIFI ex-MED baseline.

9

10 **Q86. Which reliability investments are included in the model?**

11 A86. The model's purpose is to forecast system reliability based on outage events on the
12 overhead distribution system (where the vast majority of the Company's outage
13 events occur), and therefore incorporates the impact of projects and programs
14 which have the potential reduce the impact of overhead outage events. The model
15 accounts for reliability improvements from six programs: Tree Trimming, 4.8kV
16 Hardening, PTMM, Customer Excellence, 4.8kV Conversion, and Automation.

17

18 **Q87. How does the company estimate the effectiveness of the reliability
19 investments?**

20 A87. For programs that have been established for over 3 years, the Company looks at a
21 year worth of non-MED historical circuit outage data before reliability
22 improvement is deployed. Non-MED event data for years post deployment is
23 compared to the baseline to calculate the reliability improvement. For newer
24 programs or projects, the reliability improvement is based either on the assessment
25 from industry subject matter experts, including DTE's Engineering, or by

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1 comparing the newer program to similar established programs.
2 Programs impact the event types they are most likely to avoid. For example, if a
3 circuit has tree trimming planned, the model will project a reduction in tree-related
4 multiple events.

5

6 **Q88. How is the circuit performance projected?**

7 A88. The investment plan is entered in the model on a circuit level basis. For example,
8 the model has a list of circuits with planned PTMM in 2024 which is aligned with
9 our investment plan. If a circuit has no planned investment indicated in the model,
10 the model will calculate an increase in future event volume, or degradation, over
11 time. Circuits which have Tree Trimming, 4.8kV Hardening, PTMM, or Customer
12 Excellence work will have the program benefits applied to them by reducing the
13 future volume of events. Half of the maximum benefit will be applied in the year
14 of the investment, and the total benefit in the year after the investment. The benefit
15 will reduce over time due to factors such as the regrowth of trees, and the continued
16 aging of overhead equipment. The model assumes that significant rebuild work
17 from 4.8kV Conversion will deliver a consistent benefit for 10 years after the
18 investment without any degradation. The impact of the Automation investment is a
19 reduction in the customer interrupted (CI) per event on the circuit, but there is no
20 associated reduction in event volume.

21

22 **Q89. How are Ex-MED and all-weather reliability metrics calculated?**

23 A89. The primary output of the model is a projection of ex-MED event volume, which
24 is translated into SAIFI ex-MED and SAIDI ex-MED using a historical event
25 average CI and CMI per event. The ex-MED results are scaled to all-weather

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1 projections by calculating the ex-MED to all weather performance relationship of
2 64 large utilities based on historical data available on EIA.gov. As an example, for
3 utilities who had a SAIDI ex-MED of 100 minutes in a given year, the range of All-
4 Weather SAIDI outcomes, excluding the top and bottom 20% of outcomes, was
5 140 minutes to 342 minutes. If the model projects the Company's SAIDI ex-MED
6 performance to be 100 minutes, it would also calculate a range of expected All-
7 weather outcomes to be 140 to 342 minutes, with an average performance
8 calculated as the median of the data set. This range, based on industry performance,
9 accounts for weather variability.

10

11 **Q90. Does the model capture all potential reliability benefits?**

12 A90. No, as mentioned the model captures the benefits of the investment programs which
13 deliver the majority of the improvements on the overhead distribution system.
14 Other programs such as URD replacement, Cable replacement, Breaker
15 replacement, Substation Risk projects will also reduce outage events and impact
16 reliability. For specific benefits from these projects, please refer to testimony from
17 Witnesses Elliott Andahazy, Deol, and Hartwick.

18

19 **Q91. How is this model an improvement upon previous reliability projections?**

20 A91. The structure of this model has many improvements over previous methods to
21 project reliability. First, the model is based on ex-MED events and reliability which
22 has less inherent variability than all-weather performance. Second, by modelling
23 the system on a circuit level basis, this methodology more accurately accounts for
24 benefits from different programs without double counting. Finally, as circuit
25 performance is disaggregated into many event types (tree vs non tree, single vs

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1 multiple, outage vs non-outage), program improvements can more accurately be
2 modelled against the events they are most likely to address.

3

4 **Q92. Does the reliability model project emergent reductions and how are these**
5 **reductions shown in Exhibit A-12 Schedule B5.4?**

6 A92. Yes. The reliability model projected emergent reduction, along with the surge tree
7 trim capital reduction shown on Exhibit A-22, Schedule L1, line 33, are shown in
8 Exhibit A-12, Schedule B5.4, page 1, line 6.

9

10 **Part X: IIJA Grant Opportunities**

11 **Q93. What are IIJA grants?**

12 A93. The Infrastructure Investment and Jobs Act (IIJA) was enacted federally in
13 November 2021. The goal of the IIJA grants is to provide funding opportunities in
14 multiple types of investments to catalyze public and private investment to enhance
15 the nation's infrastructure, with a particular focus on helping America's
16 disadvantaged communities. For electric infrastructure, the grants are mainly
17 administered in three broad categories: improving grid resilience, building smart
18 grids, and pursuing grid innovation.

19

20 **Q94. Did the Company seek grant funding to invest in the distribution system in**
21 **2023?**

22 A94. Yes. In 2023, the Company applied for two direct grants to improve the distribution
23 system: Section 40101(c) – Grid Resilience and Section 40107 – Smart Grid. The
24 company also applied for a grant from the Michigan Department of Environment,
25 Great Lakes, and Energy (EGLE), who is administering funds awarded through

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1 Section 40101(d) – Preventing Outages and Enhancing the Resilience of the
2 Electric Grid. Additionally, the Company was a partner on an application for
3 Section 40103(b) – Grid Innovation Program. This grant was led by the State of
4 Michigan.

5

6 **Q95. Were any of the Company’s IIJA grant applications selected to be funded?**

7 A95. Yes. The DOE (Department of Energy) selected the Company’s Section 40107 –
8 Smart Grid application for investment in October 2023. This project will deploy
9 Adaptive Network Microgrids (ANM) on the distribution system in two
10 communities and is discussed in Witness Hartwick’s testimony. The Company
11 received positive feedback on its Section 40101(c) – Grid Resilience grant from the
12 DOE on the application, although was not selected. The Company is currently
13 waiting to hear the outcome for its Section 40101 (d) – Preventing Outages and
14 Enhancing the Resilience of the Electric Grid application filed on November 17th,
15 2023. DTE Electric expects a response from EGLE in the first half of 2024.

16

17 **Q96. Will the Company continue to seek additional IIJA grant funding to invest in**
18 **the distribution system in 2024?**

19 A96. Yes. The Company is currently pursuing the second round of funding for Section
20 40101 (c) – Grid Resilience, incorporating the feedback from the DOE on project
21 scope and strategic alignment. The Company filed a concept paper on January 12,
22 2024 and will continue to update our IIJA grant planning as requested with reports
23 filed in U-21227.

24

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1 **Q97. What are the objectives and details of the 40101(d) Preventing Outages and**
2 **Enhancing the Resilience of the Electric Grid grant?**

3 A97. Unlike the two grants (Section 40101c and Section 40107), this grant is an indirect
4 grant for which the Company cannot directly apply. Instead, EGLE applied for
5 DOE funding with the support of the MPSC. EGLE was awarded the grant on June
6 30, 2023 and the Request for Proposal (RFP) was posted on EGLE's website on
7 October 3, 2023. The objectives of this grant are similar to the 40101(c) grant, with
8 a focus on improving energy resilience and investing in modernized grid
9 infrastructure, and are restricted to large utilities applicants. Overall, EGLE intends
10 to award approximately \$8 million in funding between the two largest utilities in
11 the state of Michigan (DTE Electric and Consumers Energy). The Company filed
12 an application on November 17, 2023. The Company's grant proposal is to support
13 activities that will harden and modernize electric services for residential customers
14 in Detroit and Highland Park with the impact of reducing electrical service outages
15 during storm for disadvantaged communities. These outages can have significant
16 economic impact due to loss of food or medicine, and cost of temporary shelter.
17 The proposal will investigate the most viable option to scale up a program to harden
18 electric service lines within the Company's service territory. Amongst the proposed
19 options for hardening services are (1) undergrounding overhead services, and (2)
20 replacing overhead services and tree trimming away from services. Additionally,
21 newly hardened residential services will be brought up to the Company's current
22 standard and will be capable of supporting future electrification.

23

24 **Q98. Is the Company requesting funding in this rate case for investments or**
25 **expenses that may be partially covered by any of the grants discussed above?**

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1 A98. Yes. The investment beyond the grant funding needed for the Section 40107 - Smart
2 Grid award is covered in the Adaptive Networked Microgrid section of Witness
3 Hartwick's testimony. The Company is not seeking funding for the other two grants
4 that are still being pursued in this rate case.

5

6 **Q99. If the Company is successful at obtaining any of the grants discussed above
7 but not yet awarded, what will the Company's financial obligation be?**

8 A99. For the grants the Company is actively pursuing, a 1:1 funding match of federal
9 funds will be required. For example, in the 40101(c) grant application, if DOE
10 awards \$100 million of funding, DTE would need to contribute a minimum of \$100
11 million in matching funds. DTE Electric customers would receive system
12 improvements through the federal grants without having to fund the full investment
13 in the project(s) through electric rates. Because this case does not include any
14 requested investment for DTE Electric's match, it is expected that the cost recovery
15 for the Company's match amounts would be requested in future rate cases.

16

17 **Q100. What happens if the grant requires that the Company provide matching
18 funding for a grant project before it can be presented for approval in a future
19 rate case?**

20 A100. The Company will notify the Commission through the ongoing docket on IIJA
21 grants (U-21227) and discuss needed adjustments to the capital plan and funding
22 allocations.

23

24 **Part XI: Environmental Justice**

25 **Q101. How does the Company define environmental justice (EJ)?**

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1 A101. The Company defines EJ in the context of the State of Michigan’s definition of
2 environmental justice as “the equitable treatment and meaningful involvement of
3 all people, regardless of race, color, national origin, ability, or income in the
4 development and application of laws, regulations, and policies that affect the
5 environment, as well as the places people live, work, play, worship, and learn.”⁸
6

7 **Q102. How did DTE Electric incorporate EJ in grid planning as described in the 2023**
8 **DGP?**

9 A102. Building on the 2021 DGP, the Company developed three key EJ objectives for the
10 2023 DGP; (1) incorporate EJ considerations in investment decisions by including
11 an EJ component in the Global Prioritization Model (GPM), (2) improve system
12 performance for vulnerable communities experiencing poor reliability through our
13 investment programs, and (3) provide support to vulnerable customers experiencing
14 outages during storms through community outreach efforts.
15

16 **Q103. Does the Company continue to leverage the State of Michigan MiEJScreen tool**
17 **for environmental justice data and the identification of vulnerable**
18 **communities?**

19 A103. Yes. DO continues to use the MiEJScreen Tool for its EJ data in analyzing
20 investment impacts on disadvantaged customers and communities. EGLE released
21 the draft version of the MiEJScreen tool in March of 2022, following extensive
22 stakeholder involvement including a public comment process.⁹ This tool combines
23 environmental conditions and population characteristics to highlight, by census

⁸ [State of Michigan, Department of Environment, Great Lakes, and Energy, https://www.michigan.gov/egle/public/learn/environmental-justice, accessed January 23, 2024.](https://www.michigan.gov/egle/public/learn/environmental-justice)

⁹ [MiEJScreen: Environmental Justice Screening Tool \(DRAFT\) \(michigan.gov\) available at https://www.michigan.gov/egle/maps-data/miejscreen?adlt=strict](https://www.michigan.gov/egle/maps-data/miejscreen?adlt=strict)

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1 tract, where the most vulnerable communities in Michigan are located. EGLE does
2 not explicitly define the threshold for which communities are vulnerable and which
3 ones are not vulnerable. A final MiEJScreen tool has not been released.

4

5 **Q104. How did DTE Electric Distribution Operations define a vulnerable community**
6 **for use with the draft MiEJScreen Tool?**

7 A104. An 80% threshold definition was adopted for vulnerable communities using the
8 draft MiEJScreen Tool score, consistent with the U.S. EPA approach.¹⁰ Following
9 this approach, census tracts with a MiEJScreen composite score at or above the 80th
10 percentile are considered vulnerable communities for the purpose of this testimony
11 and associated analysis. The draft MiEJScreen composite score is calculated using
12 categories and indicators for environmental and population data as shown in **Figure**
13 **11** below. On November 18, 2022 the Commission directed its Energy
14 Affordability and Accessibility Collaborative to address definitions of terms such
15 as environmental justice, grid equity, and energy justice (Case No. U-20836, pp
16 462-463).

¹⁰ 80th percentile, EPA, <https://www.epa.gov/ejscreen/frequent-questions-about-ejscreen#q5>, accessed January 24, 2024.

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Figure 11 MiEJScreen Overall Score Calculation

Categories	Environmental Exposure	Environmental Effects	Sensitive Populations	Socioeconomic Factors
Indicators	NATA Air Toxics Cancer Risk NATA Respiratory Hazard Index NATA Diesel Particulate Matter Particulate Matter (PM _{2.5}) Ozone Traffic Density	Proximity to Cleanup Sites Proximity to Hazardous Waste Facilities Impaired Water Bodies Proximity to Solid waste Sites and Facilities Lead Paint Indicator Proximity to RMP Sites Wastewater Discharge Indicator	Asthma Cardiovascular Disease Low Birth Weight Infants Blood Lead Level Life Expectancy	Low Income Population Black, Indigenous, People of Color Population Educational Attainment Linguistic Isolation Population Under Age 5 Population Over Age 64 Unemployment Housing Burden
Sub Scores	Environmental Conditions (Average percentile of Environmental Exposure indicators + 0.5 x average percentile of Environmental Effects indicators) <u>1.5</u>		Population Characteristics (Average percentile of Sensitive Population indicators + average percentile of Socioeconomic Factor indicators) <u>2</u>	
Score	Final Composite Score = Environmental Conditions score x Population Characteristics score MiEJScreen Score			

2

3 **Q105. Is the Company able to group reliability statistics by geographic area (i.e.,**
 4 **census tracts and zip codes) and align to scores from the draft MiEJScreen**
 5 **Tool?**

6 A105. Yes. DTE Electric tracks reliability statistics by customer, which are then rolled up
 7 to a circuit and substation. However, circuits often cross more than one census tract
 8 or zip code. DTE Electric has matched residential meters to the census tracts
 9 defined by the U.S. Census Bureau. Commercial properties are not surveyed as part
 10 of the U.S. Census, and therefore, their addresses and associated meters are not
 11 assigned to a census tract for the purposes of this analysis. There are some
 12 residential meters, due to ongoing data cleaning work, that have yet to be placed in
 13 a census tract/zip code. Currently, most meters have been successfully mapped to

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1 zip code and census tract. There are some small census tracts with a small number
2 of customers where reliability statistics may be abnormally high or low due to small
3 sample size.

4

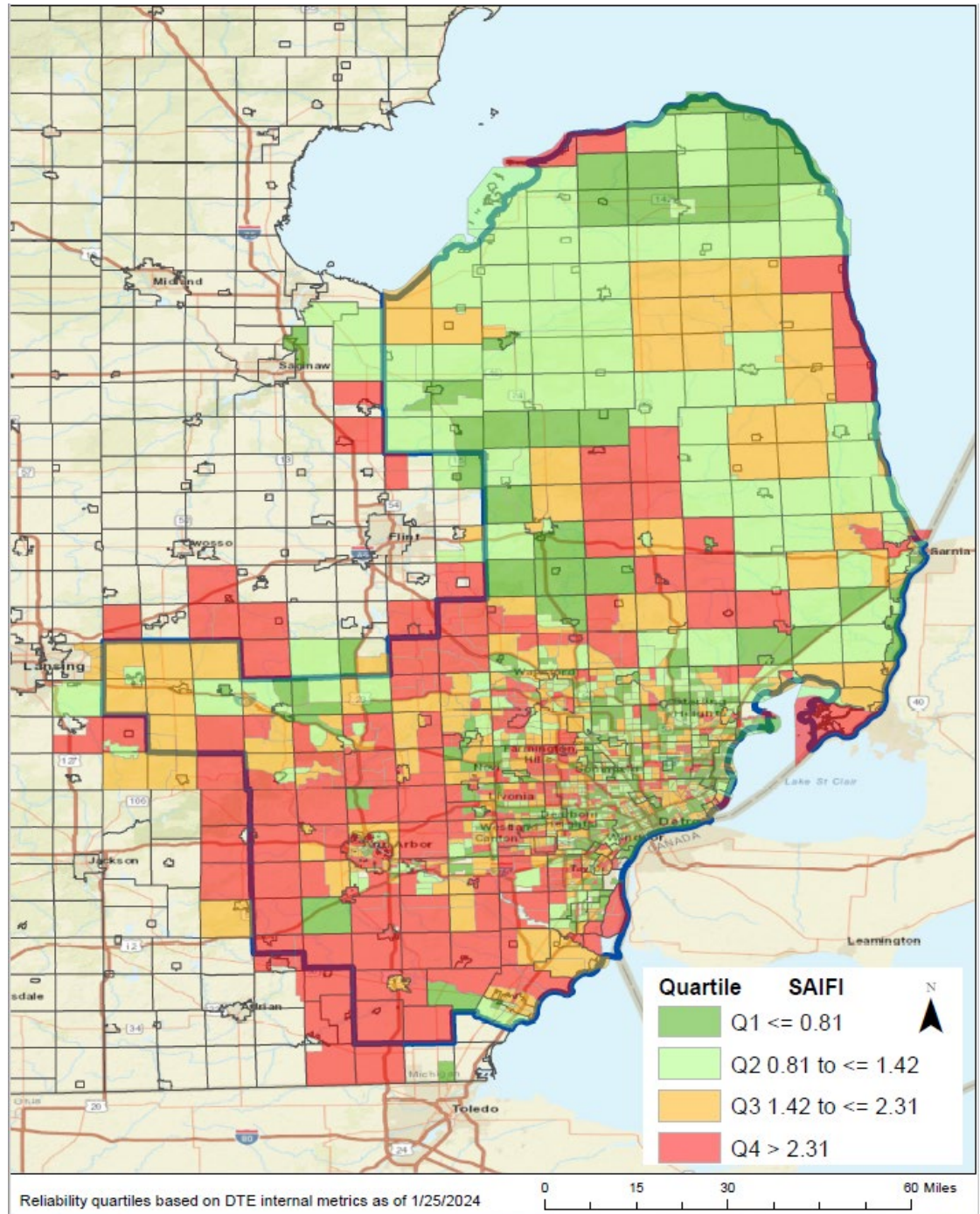
5 **Q106. Using available data, is the Company able to provide a geographic**
6 **representation of 2023 electric reliability data by census tracts?**

7 A106. Yes. Using the meters that are matched to census tracts, DTE Electric developed
8 reliability data for SAIFI and SAIDI by census tract and grouped the data into DTE
9 Electric reliability quartiles, with first quartile customers (shown below in green)
10 experiencing the best reliability and fourth quartile customers (shown below in red)
11 experiencing the worst reliability. Looking specifically at outage frequency, first
12 quartile reliability customers have a 2023 All-Weather SAIFI performance fewer
13 than 0.81 interruptions, second quartile customers range between 0.81 and 1.42
14 interruptions, third quartile customers are between 1.42 and 2.31 interruptions, and
15 fourth quartile customers have performance greater than 2.31 interruptions.
16 Looking at outage duration, first quartile reliability customers have a 2023 All-
17 Weather SAIDI performance less than 331 minutes, second quartile customers
18 range between 331 and 957 minutes, third quartile customers are between 957
19 minutes and 2,140 minutes, and fourth quartile customers have experienced outage
20 duration above 2,140 minutes. As discussed in Part I above, for 2023, a key impact
21 on All-Weather SAIDI was the single large ice/snow storm in February, 2023,
22 which significantly impacted both SAIDI and SAIFI reliability metrics. Maps for
23 SAIFI and SAIDI by census tract are included in **Figure 12 to Figure 15**.

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**Figure 12 2023 All Weather SAIFI by Census Tract
for DTE Electric (Full Electric Service Area)**

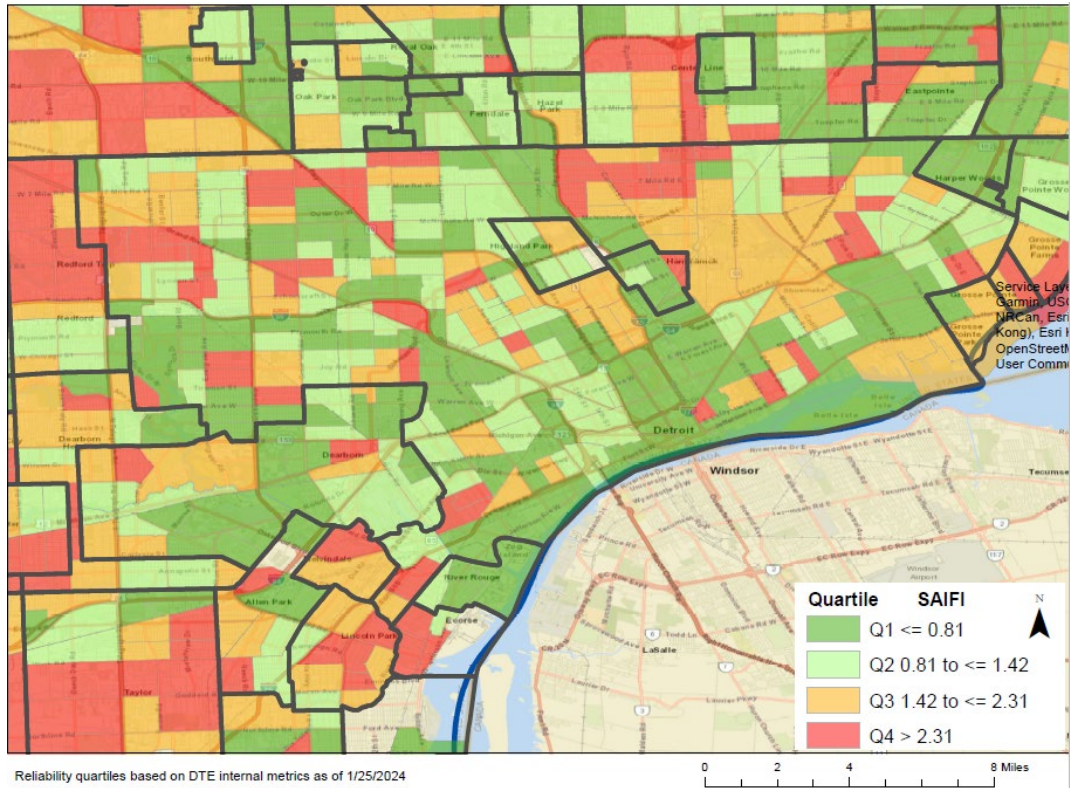


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**Figure 13 2023 All Weather SAIFI by Census Tract
for DTE Electric (Metro Detroit Area)**



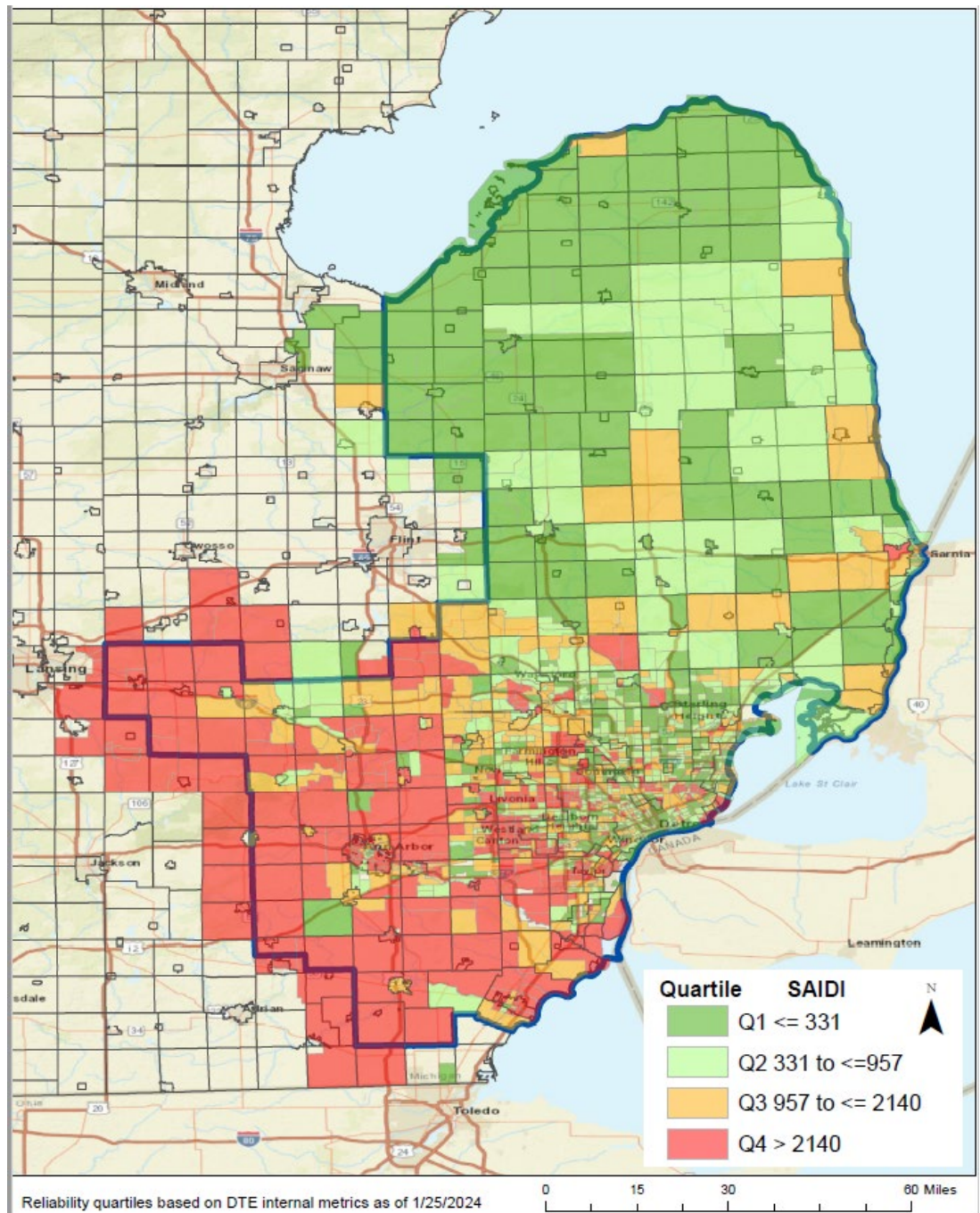
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Figure 14 2023 All Weather SAIDI by Census Tract

2

for DTE Electric (Full Electric Service Area)

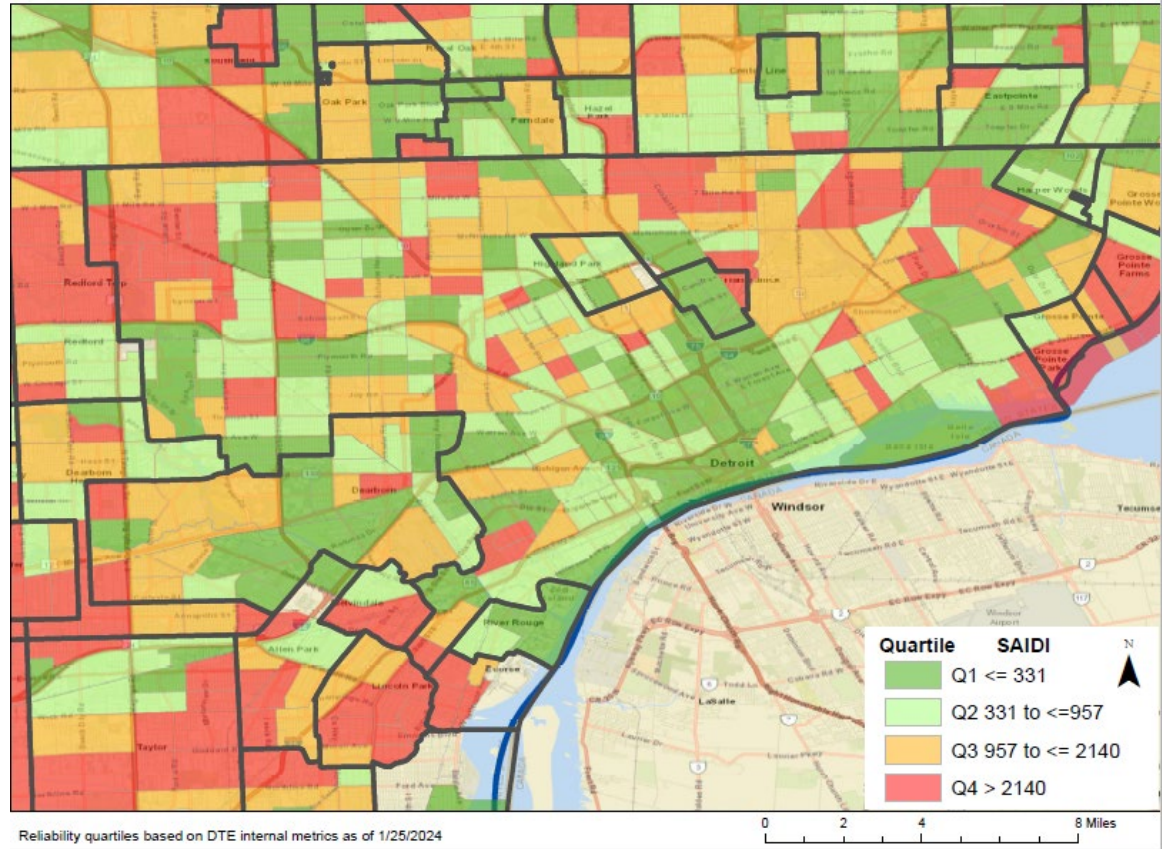


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**Figure 15 2023 All Weather SAIDI by Census Tract
for DTE Electric (Metro Detroit Area)**



3

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1 **Q107. Are all census tracts equal in geographic size and population?**

2 A107. No. Census tracts vary in geographic size and population. According to the U.S.
3 Census Bureau, census tracts generally have a population size between 1,200 and
4 8,000 people, with an optimum size of 4,000 people.¹¹ In addition, the geographical
5 size of the tract does not represent how many people are in it. In some areas there
6 are large tracts (both first and fourth quartile) that have fewer customers in them,
7 compared to much smaller sized tracts in more dense urban areas. When the
8 reliability data is looked at in a map, as shown above, the lightly populated,
9 geographically large census tracts can visually skew the true reliability impact on
10 customers.

11

12 **Q108. How many vulnerable census tracts are there in DTE Electric's service**
13 **territory?**

14 A108. In the DTE Electric service territory, there are 483 census tracts that fall into the
15 range of having a composite draft MiEJScreen score at or above 80th percentile.
16 These 483 census tracts represent 29% of the total census tracts in DTE Electric's
17 service area and account for approximately 550,000 residential customers.¹²
18 Additionally, these tracts include a total of 1,032 circuits out of DTE Electric's
19 3,273 distribution circuits (32% of total circuits) and contain 8,289 circuit miles
20 compared to 41,905 total distribution circuit miles (20% of total distribution miles).

21

22 **Q109. What was the Commission's direction in Case No. U-21297 regarding more in-**
23 **depth EJ analysis?**

¹¹ US Census Bureau, Glossary, available at [Glossary \(census.gov\)](https://www.census.gov/programs-surveys/geography/about/glossary.html?adlt=strict#par_textimage_13), https://www.census.gov/programs-surveys/geography/about/glossary.html?adlt=strict#par_textimage_13 accessed January 14, 2023.

¹² There are a total of 1,643 census tracts in DTE Electric's service territory.

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1 A109. The Commission stated in its order that future analysis of the MiEJScreen data
2 should be segmented in 5% gradations. As stated on page 93 of the U-21297 order:
3 “The Staff recommends, and the Commission agrees, that these gradations should
4 be defined initially as 0% to <5%, 5% to <10%, in 5% gradations up to 95%-100%
5 of the MiEJScreen composite score”.

6

7 **Q110. Has the Company performed analysis with 5% gradations of the MiEJScreen**
8 **relative to reliability performance?**

9 A110. Yes. The reliability performance in years 2020 through 2023, for SAIDI and SAIFI
10 metrics excluding MEDs and All-Weather compared to the systemwide levels are
11 shown in **Tables 10-13**.

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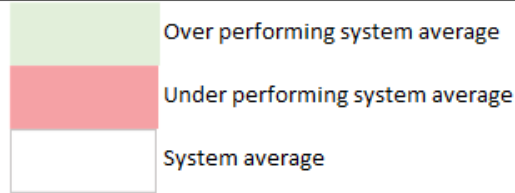
Table 10 All Weather SAIFI Reliability Performance of Census Tracts

2

(MiEJ score of 0% to 100%) Versus System Average

3

Census Tract EJ % Group	Category	2020 SAIFI	2021 SAIFI	2022 SAIFI	2023 SAIFI
0 to 5	AW	3.12	2.88	2.37	3.01
>5 to 10	AW	2.46	2.47	1.95	2.22
>10 to 15	AW	1.68	2.29	1.94	1.97
>15 to 20	AW	2.13	2.00	1.49	2.02
>20 to 25	AW	1.55	2.29	1.56	2.15
>25 to 30	AW	1.47	2.01	1.43	1.99
>30 to 35	AW	1.26	1.96	1.49	1.93
>35 to 40	AW	1.32	1.72	1.31	2.21
>40 to 45	AW	1.08	1.50	1.12	1.86
>45 to 50	AW	1.42	1.58	1.17	1.64
>50 to 55	AW	1.25	1.53	1.16	1.68
>55 to 60	AW	1.10	1.39	1.37	1.52
>60 to 65	AW	1.18	1.29	0.96	1.51
>65 to 70	AW	1.15	1.48	1.18	1.90
>70 to 75	AW	1.29	1.58	1.13	1.58
>75 to 80	AW	1.20	1.50	1.08	1.71
>80 to 85	AW	1.23	1.56	1.18	1.47
>85 to 90	AW	1.11	1.14	1.12	1.54
>90 to 95	AW	1.04	1.33	1.03	1.52
>95 to 100	AW	0.83	1.19	1.15	1.49
No EJ Score	AW	0.83	0.92	1.01	1.27
System Average	AW	1.29	1.58	1.25	1.72



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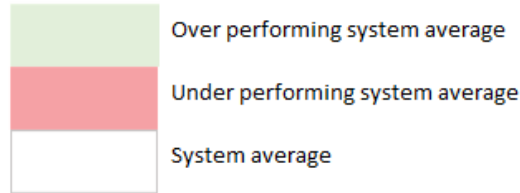
Table 11 Excluding MEDs SAIFI Reliability Performance of Census

2

Tracts (MiEJ score of 0% to 100%) Versus System Average

3

Census Tract EJ % Group	Category	2020 SAIFI	2021 SAIFI	2022 SAIFI	2023 SAIFI
0 to 5	Ex-MED	2.36	1.84	1.94	1.56
>5 to 10	Ex-MED	1.71	1.35	1.54	1.27
>10 to 15	Ex-MED	1.17	1.47	1.55	1.01
>15 to 20	Ex-MED	1.57	1.15	1.25	1.17
>20 to 25	Ex-MED	1.15	1.42	1.33	1.15
>25 to 30	Ex-MED	1.12	1.16	1.17	1.13
>30 to 35	Ex-MED	0.97	1.06	1.16	0.88
>35 to 40	Ex-MED	1.02	0.99	1.00	1.10
>40 to 45	Ex-MED	0.91	0.85	0.88	0.81
>45 to 50	Ex-MED	1.14	0.94	0.98	0.75
>50 to 55	Ex-MED	1.07	0.85	0.91	0.82
>55 to 60	Ex-MED	0.88	0.84	1.10	0.77
>60 to 65	Ex-MED	0.95	0.76	0.75	0.75
>65 to 70	Ex-MED	0.98	0.84	0.98	0.93
>70 to 75	Ex-MED	1.07	0.95	0.90	0.75
>75 to 80	Ex-MED	1.01	0.93	0.85	0.87
>80 to 85	Ex-MED	0.93	0.92	0.92	0.70
>85 to 90	Ex-MED	0.85	0.68	0.78	0.71
>90 to 95	Ex-MED	0.80	0.78	0.76	0.71
>95 to 100	Ex-MED	0.65	0.64	0.77	0.78
No EJ Score	Ex-MED	0.71	0.58	0.86	0.60
System Average	Ex-MED	1.01	0.92	0.98	0.86



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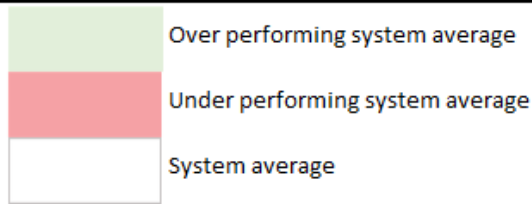
Table 12 All Weather SAIDI Reliability Performance of Census Tracts

2

(MiEJ score of 0% to 100%) Versus System Average

3

Census Tract EJ % Group	Category	2020 SAIDI	2021 SAIDI	2022 SAIDI	2023 SAIDI
0 to 5	AW	978	2656	1262	3278
>5 to 10	AW	863	1657	909	1604
>10 to 15	AW	384	930	916	1618
>15 to 20	AW	605	1096	576	1184
>20 to 25	AW	510	1291	527	1937
>25 to 30	AW	414	1174	611	1521
>30 to 35	AW	306	1211	692	1748
>35 to 40	AW	351	1027	666	1889
>40 to 45	AW	222	940	433	1834
>45 to 50	AW	330	999	426	1584
>50 to 55	AW	292	946	458	1482
>55 to 60	AW	300	775	531	1268
>60 to 65	AW	297	764	473	1363
>65 to 70	AW	228	816	416	1745
>70 to 75	AW	336	844	472	1515
>75 to 80	AW	325	820	389	1509
>80 to 85	AW	480	978	556	1419
>85 to 90	AW	351	705	735	1699
>90 to 95	AW	329	840	749	1675
>95 to 100	AW	266	804	923	1133
No EJ Score	AW	203	355	300	778
System Average	AW	352	927	584	1542



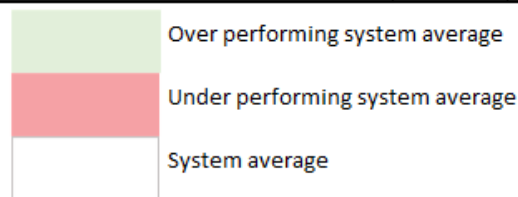
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Table 13 Excluding MEDs SAIDI Reliability Performance of Census Tracts (MiEJ score of 0% to 100%) Versus System Average

Census Tract EJ % Group	Category	2020 SAIDI	2021 SAIDI	2022 SAIDI	2023 SAIDI
0 to 5	Ex-MED	342	398	487	373
>5 to 10	Ex-MED	291	213	296	320
>10 to 15	Ex-MED	153	209	274	236
>15 to 20	Ex-MED	218	150	238	212
>20 to 25	Ex-MED	168	248	182	239
>25 to 30	Ex-MED	176	177	188	217
>30 to 35	Ex-MED	123	136	152	158
>35 to 40	Ex-MED	147	138	146	173
>40 to 45	Ex-MED	108	111	103	152
>45 to 50	Ex-MED	154	149	131	135
>50 to 55	Ex-MED	144	124	128	136
>55 to 60	Ex-MED	102	112	150	155
>60 to 65	Ex-MED	132	114	138	139
>65 to 70	Ex-MED	101	131	120	138
>70 to 75	Ex-MED	154	122	115	119
>75 to 80	Ex-MED	124	128	106	145
>80 to 85	Ex-MED	158	147	156	149
>85 to 90	Ex-MED	123	111	123	130
>90 to 95	Ex-MED	136	112	115	129
>95 to 100	Ex-MED	118	94	129	142
No EJ Score	Ex-MED	97	68	98	80
System Average	Ex-MED	142	136	146	157



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8

Q111. What is the distribution of residential customers in each EJ Gradation?

A111. The distribution of residential customer in each gradation is highlighted in **Table 14** below. Approximately 27% of our residential customers fall into the 80% to 100% gradations.

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Table 14 Residential Customers by EJ Gradations

Census Tract EJ % Group	Number of Residential Customers	% of Residential Customers
0-5%	7,569	<1%
5-10%	39,705	2%
10-15%	62,143	3%
15-20%	43,497	2%
20-25%	59,888	3%
25-30%	88,033	4%
30-35%	100,487	5%
35-40%	99,318	5%
40-45%	102,680	5%
45-50%	114,416	6%
50-55%	120,730	6%
55-60%	135,206	7%
60-65%	124,240	6%
65-70%	126,463	6%
70-75%	100,278	5%
75-80%	146,161	7%
80-85%	127,270	6%
85-90%	162,145	8%
90-95%	143,144	7%
95-100%	114,874	6%
Unmapped/Unscored*	38,383	2%
Total Residential Customers	2,056,630	100%

2

3 **Q112. How does the reliability performance of census tracts that have been identified**
4 **as vulnerable communities compare with the rest of the DTE Electric system?**

5 A112. As noted in **Table 10** and **Table 12**, vulnerable customers in the 80th percentile and
6 above see better reliability than the system average in SAIFI and SAIDI in both
7 All-Weather and Non-MED. All-Weather and Non-MEDs SAIFI is lower than the
8 system average in every year and every vulnerable community gradient. For Non-
9 MED SAIDI, the vast majority of years and vulnerable community gradients are
10 better than the system average. All-Weather shows more year-gradient
11 combinations above the system average but even for this metric, the majority of
12 instances are better than the system average.

13

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1 **Q113. Has the company evaluated how its investment programs are reaching**
2 **vulnerable communities to improve electric distribution infrastructure and**
3 **reliability performance?**

4 A113. Yes. The Company has evaluated some of its largest distribution investment
5 projects and programs, 4.8kV Hardening, 4.8kV Conversion, and tree trim, with
6 respect to if the investment was made in a vulnerable area.

7

8 **Q114. What are the results of the investment analysis related to vulnerable**
9 **communities?**

10 A114. The results are summarized in **Table 15** below and indicate that the Company's
11 investments are supporting vulnerable customers and communities in southeast
12 Michigan, including the City of Detroit. This analysis is based on the draft
13 MiEJScreen Tool census tract data and Company investment data on the circuits
14 addressed by the following three programs over the timeframe 2018-2023: 4.8kV
15 Hardening, Tree Trimming and Conversions. For each of these investment
16 programs, **Table 15** shows total investment dollars by program, total program
17 investment in vulnerable communities, and percentage of program investment in
18 vulnerable communities. For example, of the nearly half billion dollars of
19 investment in the 4.8kV Hardening program since 2018, 85% of work performed
20 under the hardening program occurred in vulnerable communities. As discussed by
21 Witness Elliott Andahazy, the hardening program has resulted in documented
22 reliability and safety improvements, including reduction in the frequency and
23 duration of outages and fewer downed wires, through the program's clearing of
24 right of way, equipment upgrades, and removal of arc wire.

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Table 15 2018 to 2023 Investment in Vulnerable Communities (Census

2

Tracts with MiEJ Score of 80% to 100%)

3

Investment Program (2018-2023)	Total Investment by Program (\$M)	Total Investment by Program in Vulnerable Census Tracts (\$M)	% Of Investment in Vulnerable Census Tracts
Conversion	\$396	\$255	64%
4.8kV Hardening	\$494	\$418	85%
Tree Trim	\$962	\$242	25%

4

5

Q115. How will these distribution investment programs address vulnerable communities in 2024-2025 based on the Company’s planned execution of investments in this case?

6

7

A115. For the purpose of this analysis, the Company focused on three of the largest strategic investment programs, Witness Deol, Witness Elliott Andahazy, and Witness Steudle address the Company’s planned investments for 2024 and 2025 for conversions, hardening, and tree trimming, respectively. **Table 16** below summarizes total investment dollars by program, total program investment in vulnerable communities, and percentage of program investment in vulnerable communities in 2024-2025.

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1 **Table 16 2024-2025 Investment in Vulnerable Communities (Census**
 2 **Tracts with MiEJ Score of 80% to 100%)**

3

Investment Program (2024-2025)	Total Investment by Program (\$M)	Total Investment by Program in Vulnerable Census Tracts (\$M)	% Of Investment in Vulnerable Census Tracts
Conversion	\$475	\$288	61%
4.8kV Hardening	\$205	\$185	90%
Tree Trim	\$285	\$81	28%

4

5 **Q116. Is the Company also analyzing investments in 5% EJ gradations as directed**
 6 **in the December 2023 order in Case No. U-21297?**

7 A116. Yes. The Company analyzed investments pertaining to Hardening, Tree Trim, and
 8 Conversion including City of Detroit Infrastructure (CODI) programs, to provide
 9 information in EJ community gradations based on the MiEJScreen score as defined
 10 in the December 2023 order. The gradations are defined as 0% to 5%, >5% to 10%,
 11 in 5% gradations up to >95% - 100% of the MiEJScreen composite score, the same
 12 as the reliability analysis above. **Tables 17 to Table 22** below demonstrates the
 13 Company's investment distribution for EJ gradations by year.

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Table 17 Hardening Investments by EJ Gradations

2

EJ Gradations	2018 Investment (\$000)	2019 Investment (\$000)	2020 Investment (\$000)	2021 Investment (\$000)	2022 Investment (\$000)	2023 Investment (\$000)	2024 Investment Forecast (\$000)	2025 Investment Forecast (\$000)
0-5%	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,710	\$ -	\$ -
5-10%	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
10-15%	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
15-20%	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
20-25%	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
25-30%	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
30-35%	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
35-40%	\$ -	\$ -	\$ -	\$ -	\$ 1,955	\$ -	\$ -	\$ -
40-45%	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
45-50%	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
50-55%	\$ -	\$ -	\$ -	\$ 6,284	\$ -	\$ -	\$ -	\$ -
55-60%	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 211	\$ -
60-65%	\$ -	\$ -	\$ -	\$ 1,669	\$ 9,026	\$ -	\$ -	\$ -
65-70%	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
70-75%	\$ 1,077	\$ 2,300	\$ 1,821	\$ 3,032	\$ 2,747	\$ -	\$ -	\$ 7,401
75-80%	\$ 2,302	\$ -	\$ 868	\$ 16,682	\$ 1,691	\$ 4,148	\$ 2,177	\$ 1,595
80-85%	\$ 5,455	\$ 12,499	\$ 2,343	\$ 646	\$ 8,354	\$ 12,660	\$ -	\$ 3,777
85-90%	\$ 14,205	\$ 18,366	\$ 24,086	\$ 8,858	\$ 22,658	\$ 32,545	\$ 7,681	\$ 21,978
90-95%	\$ 16,413	\$ 13,456	\$ 15,495	\$ 13,563	\$ 39,625	\$ 24,866	\$ 20,547	\$ 44,776
95-100%	\$ 776	\$ 1,644	\$ 9,505	\$ 12,315	\$ 65,540	\$ 40,755	\$ 45,717	\$ 40,409
Unmapped/Unscored*	\$ 95	\$ 12	\$ 1,048	\$ 2,313	\$ 5,885	\$ 10,326	\$ 3,667	\$ 5,063
Total Investment (\$)	\$ 40,325	\$ 48,278	\$ 55,165	\$ 65,362	\$ 157,482	\$ 127,010	\$ 80,000	\$ 125,000

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Table 18 Percent of Hardening Investments by EJ Gradations

EJ Gradations	2018 Investment (%)	2019 Investment (%)	2020 Investment (%)	2021 Investment (%)	2022 Investment (%)	2023 Investment (%)	2024 Investment Forecast (%)	2025 Investment Forecast (%)
0-5%	0%	0%	0%	0%	0%	1%	0%	0%
5-10%	0%	0%	0%	0%	0%	0%	0%	0%
10-15%	0%	0%	0%	0%	0%	0%	0%	0%
15-20%	0%	0%	0%	0%	0%	0%	0%	0%
20-25%	0%	0%	0%	0%	0%	0%	0%	0%
25-30%	0%	0%	0%	0%	0%	0%	0%	0%
30-35%	0%	0%	0%	0%	0%	0%	0%	0%
35-40%	0%	0%	0%	0%	1%	0%	0%	0%
40-45%	0%	0%	0%	0%	0%	0%	0%	0%
45-50%	0%	0%	0%	0%	0%	0%	0%	0%
50-55%	0%	0%	0%	10%	0%	0%	0%	0%
55-60%	0%	0%	0%	0%	0%	0%	0%	0%
60-65%	0%	0%	0%	3%	6%	0%	0%	0%
65-70%	0%	0%	0%	0%	0%	0%	0%	0%
70-75%	3%	5%	3%	5%	2%	0%	0%	6%
75-80%	6%	0%	2%	26%	1%	3%	3%	1%
80-85%	14%	26%	4%	1%	5%	10%	0%	3%
85-90%	35%	38%	44%	14%	14%	26%	10%	18%
90-95%	41%	28%	28%	21%	25%	20%	26%	36%
95-100%	2%	3%	17%	19%	42%	32%	57%	32%
Unmapped/Unscored	0%	0%	2%	4%	4%	8%	5%	4%
Total Investment (%)	100%	100%	100%	100%	100%	100%	100%	100%

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Table 19 Tree Trim Investments by EJ Gradations

EJ Gradations	2018 Investment (\$000)	2019 Investment (\$000)	2020 Investment (\$000)	2021 Investment (\$000)	2022 Investment (\$000)	2023 Investment (\$000)	2024 Investment Forecast (\$000)	2025 Investment Forecast (\$000)
0-5%	\$ 553	\$ 252	\$ 948	\$ 1,634	\$ 3,055	\$ 1,487	\$ 501	\$ 303
5-10%	\$ 4,596	\$ 4,355	\$ 11,250	\$ 9,290	\$ 4,653	\$ 9,113	\$ 3,301	\$ 494
10-15%	\$ 7,087	\$ 1,076	\$ 9,756	\$ 11,195	\$ 12,626	\$ 13,319	\$ 5,131	\$ 1,161
15-20%	\$ 2,808	\$ 2,407	\$ 7,037	\$ 7,118	\$ 6,069	\$ 8,227	\$ 5,623	\$ 5,258
20-25%	\$ 2,809	\$ 5,681	\$ 8,683	\$ 7,320	\$ 11,946	\$ 5,077	\$ 11,032	\$ 12,265
25-30%	\$ 4,056	\$ 3,714	\$ 8,551	\$ 15,421	\$ 12,696	\$ 8,208	\$ 7,503	\$ 5,232
30-35%	\$ 3,008	\$ 2,815	\$ 14,158	\$ 10,839	\$ 16,395	\$ 9,867	\$ 5,498	\$ 4,543
35-40%	\$ 3,047	\$ 5,011	\$ 9,332	\$ 7,666	\$ 15,467	\$ 8,204	\$ 5,311	\$ 8,483
40-45%	\$ 3,415	\$ 2,496	\$ 4,657	\$ 8,498	\$ 13,595	\$ 7,857	\$ 3,986	\$ 3,649
45-50%	\$ 4,059	\$ 6,039	\$ 4,847	\$ 7,315	\$ 11,990	\$ 11,789	\$ 7,463	\$ 5,331
50-55%	\$ 2,204	\$ 4,604	\$ 4,730	\$ 10,125	\$ 13,127	\$ 5,841	\$ 6,768	\$ 4,540
55-60%	\$ 1,611	\$ 4,281	\$ 5,338	\$ 6,987	\$ 10,363	\$ 6,555	\$ 9,179	\$ 5,565
60-65%	\$ 1,746	\$ 3,820	\$ 5,864	\$ 7,329	\$ 9,856	\$ 5,702	\$ 3,664	\$ 4,726
65-70%	\$ 1,659	\$ 2,560	\$ 5,860	\$ 4,182	\$ 11,035	\$ 4,402	\$ 4,862	\$ 7,786
70-75%	\$ 1,028	\$ 3,209	\$ 4,676	\$ 2,664	\$ 4,782	\$ 3,696	\$ 5,259	\$ 5,338
75-80%	\$ 2,187	\$ 3,831	\$ 5,980	\$ 5,654	\$ 10,001	\$ 5,855	\$ 8,571	\$ 9,488
80-85%	\$ 4,758	\$ 4,967	\$ 3,119	\$ 8,166	\$ 15,094	\$ 5,759	\$ 8,316	\$ 10,553
85-90%	\$ 7,880	\$ 23,046	\$ 7,664	\$ 6,750	\$ 13,184	\$ 8,647	\$ 20,166	\$ 5,072
90-95%	\$ 7,856	\$ 13,901	\$ 14,559	\$ 4,648	\$ 16,324	\$ 10,152	\$ 16,101	\$ 5,868
95-100%	\$ 5,444	\$ 14,573	\$ 7,846	\$ 8,734	\$ 13,113	\$ 15,055	\$ 13,239	\$ 981
Unmapped/Unscored*	\$ 9,939	\$ 14,193	\$ 24,073	\$ 10,699	\$ 19,887	\$ 22,648	\$ 11,458	\$ 15,819
Total Investment (%)	\$ 81,752	\$ 126,831	\$ 168,926	\$ 162,235	\$ 245,260	\$ 177,459	\$ 162,930	\$ 122,456

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Table 20 Percent of Tree Trim Investments by EJ Gradations

EJ Gradations	2018 Investment (%)	2019 Investment (%)	2020 Investment (%)	2021 Investment (%)	2022 Investment (%)	2023 Investment (%)	2024 Investment Forecast (%)	2025 Investment Forecast (%)
0-5%	1%	0%	1%	1%	1%	1%	0%	0%
5-10%	6%	3%	7%	6%	2%	5%	2%	0%
10-15%	9%	1%	6%	7%	5%	8%	3%	1%
15-20%	3%	2%	4%	4%	2%	5%	3%	4%
20-25%	3%	4%	5%	5%	5%	3%	7%	10%
25-30%	5%	3%	5%	10%	5%	5%	5%	4%
30-35%	4%	2%	8%	7%	7%	6%	3%	4%
35-40%	4%	4%	6%	5%	6%	5%	3%	7%
40-45%	4%	2%	3%	5%	6%	4%	2%	3%
45-50%	5%	5%	3%	5%	5%	7%	5%	4%
50-55%	3%	4%	3%	6%	5%	3%	4%	4%
55-60%	2%	3%	3%	4%	4%	4%	6%	5%
60-65%	2%	3%	3%	5%	4%	3%	2%	4%
65-70%	2%	2%	3%	3%	4%	2%	3%	6%
70-75%	1%	3%	3%	2%	2%	2%	3%	4%
75-80%	3%	3%	4%	3%	4%	3%	5%	8%
80-85%	6%	4%	2%	5%	6%	3%	5%	9%
85-90%	10%	18%	5%	4%	5%	5%	12%	4%
90-95%	10%	11%	9%	3%	7%	6%	10%	5%
95-100%	7%	11%	5%	5%	5%	8%	8%	1%
Unmapped/Unscored*	12%	11%	14%	7%	8%	13%	7%	13%
Total Investment (%)	100%	100%	100%	100%	100%	100%	100%	100%

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Table 21 Conversion Investments by EJ Gradations

EJ Gradations	2018 Investment (\$000)	2019 Investment (\$000)	2020 Investment (\$000)	2021 Investment (\$000)	2022 Investment (\$000)	2023 Investment (\$000)	2024 Investment Forecast (\$000)	2025 Investment Forecast (\$000)
0-5%	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
5-10%	\$ -	\$ -	\$ -	\$ 127	\$ 51	\$ 399	\$ 2,079	\$ 2,735
10-15%	\$ 128	\$ 583	\$ 660	\$ 464	\$ 1,118	\$ 439	\$ 1,601	\$ 2,788
15-20%	\$ 203	\$ 618	\$ 665	\$ 2,359	\$ 5,468	\$ 1,748	\$ 5,341	\$ 1,132
20-25%	\$ 511	\$ 1,142	\$ 692	\$ 2,423	\$ 7,370	\$ 3,787	\$ 5,099	\$ 5,971
25-30%	\$ 201	\$ 483	\$ 324	\$ 523	\$ 480	\$ 2,094	\$ 6,093	\$ 4,996
30-35%	\$ 225	\$ 811	\$ 427	\$ 3,753	\$ 9,445	\$ 3,464	\$ 7,425	\$ 13,410
35-40%	\$ 339	\$ 159	\$ 112	\$ 143	\$ 329	\$ 319	\$ 484	\$ 986
40-45%	\$ 11	\$ 66	\$ -	\$ 16	\$ 65	\$ 235	\$ 433	\$ 1,824
45-50%	\$ 60	\$ 189	\$ 14	\$ 505	\$ 4,188	\$ 1,656	\$ 1,617	\$ 4,544
50-55%	\$ 1,764	\$ 784	\$ 154	\$ 380	\$ 1,141	\$ 887	\$ 2,099	\$ 5,312
55-60%	\$ 82	\$ 185	\$ 50	\$ 793	\$ 2,362	\$ 6,227	\$ 9,902	\$ (27)
60-65%	\$ 1,072	\$ 413	\$ 176	\$ 340	\$ 106	\$ 497	\$ 1,884	\$ 6,280
65-70%	\$ 877	\$ 275	\$ 58	\$ 595	\$ 1,101	\$ 8,909	\$ 16,676	\$ 144
70-75%	\$ 272	\$ 75	\$ 114	\$ 1,001	\$ 295	\$ 833	\$ 2,378	\$ 2,818
75-80%	\$ 2,313	\$ 2,497	\$ 3,125	\$ 3,149	\$ 4,188	\$ 11,090	\$ 21,576	\$ 11,318
80-85%	\$ 381	\$ 187	\$ 183	\$ 816	\$ 3,335	\$ 11,149	\$ 9,145	\$ 15,499
85-90%	\$ 1,440	\$ 495	\$ 297	\$ 2,147	\$ 4,319	\$ 11,646	\$ 9,212	\$ 17,790
90-95%	\$ 2,475	\$ 1,102	\$ 1,157	\$ 4,732	\$ 8,542	\$ 18,081	\$ 37,126	\$ 35,191
95-100%	\$ 11,423	\$ 9,836	\$ 15,814	\$ 32,162	\$ 44,649	\$ 67,524	\$ 73,157	\$ 83,132
Unmapped/Unscored*	\$ 1,653	\$ 690	\$ 437	\$ 2,665	\$ 5,930	\$ 11,126	\$ 15,237	\$ 30,475
Total Investment (\$)	\$ 25,429	\$ 20,591	\$ 24,460	\$ 59,092	\$ 104,483	\$ 162,109	\$ 228,563	\$ 246,318

2

3

Table 22 Percent of Conversion Investments by EJ Gradations

4

EJ Gradations	2018 Investment (%)	2019 Investment (%)	2020 Investment (%)	2021 Investment (%)	2022 Investment (%)	2023 Investment (%)	2024 Investment Forecast (%)	2025 Investment Forecast (%)
0-5%	0%	0%	0%	0%	0%	0%	0%	0%
5-10%	0%	0%	0%	0%	0%	0%	1%	1%
10-15%	1%	3%	3%	1%	1%	0%	1%	1%
15-20%	1%	3%	3%	4%	5%	1%	2%	0%
20-25%	2%	6%	3%	4%	7%	2%	2%	2%
25-30%	1%	2%	1%	1%	0%	1%	3%	2%
30-35%	1%	4%	2%	6%	9%	2%	3%	5%
35-40%	1%	1%	0%	0%	0%	0%	0%	0%
40-45%	0%	0%	0%	0%	0%	0%	0%	1%
45-50%	0%	1%	0%	1%	4%	1%	1%	2%
50-55%	7%	4%	1%	1%	1%	1%	1%	2%
55-60%	0%	1%	0%	1%	2%	4%	4%	0%
60-65%	4%	2%	1%	1%	0%	0%	1%	3%
65-70%	3%	1%	0%	1%	1%	5%	7%	0%
70-75%	1%	0%	0%	2%	0%	1%	1%	1%
75-80%	9%	12%	13%	5%	4%	7%	9%	5%
80-85%	1%	1%	1%	1%	3%	7%	4%	6%
85-90%	6%	2%	1%	4%	4%	7%	4%	7%
90-95%	10%	5%	5%	8%	8%	11%	16%	14%
95-100%	45%	48%	65%	54%	43%	42%	32%	34%
Unmapped/Unscored	6%	3%	2%	5%	6%	7%	7%	12%
Total Investment (%)	100%	100%	100%	100%	100%	100%	100%	100%

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1 **Q117. Is the investment in vulnerable communities reflective of DTE Electric's**
2 **ongoing efforts to improve reliability in vulnerable communities?**

3 A117. Yes. As highlighted in **Table 15**, 85%, 64%, and 25 % of the investment in the
4 4.8kV Hardening, 4.8kV Conversion, and Tree Trim programs for the time period
5 2018 to 2023 was made in vulnerable communities. Significant investment is
6 expected to continue in these vulnerable communities in future years 2024-2025 as
7 illustrated in **Table 16** including 90%, 61%, and 28% of the total investment in the
8 Hardening, Conversion, and Tree Trim. Both the Company's historical and future
9 projected investment, is consistent with DTE Electric's commitment to improving
10 reliability in vulnerable communities.

11

12 **Q118. Has the Company incorporated Environmental Justice considerations into the**
13 **GPM for future Distribution Operations investments, including investments**
14 **in this case?**

15 A118. Yes. As described in the DGP section of testimony above, the Company has
16 included EJ scoring from the MiEJScreen tool in the GPM calculation. Projects in
17 more vulnerable areas will receive a higher score and have a better chance of being
18 selected for investment.

19

20 **Q119. How is the Company addressing the circuits with the worst reliability that**
21 **have also been identified as serving vulnerable customers?**

22 A119. The Company has either already invested in recent improvements or has plans to
23 improve performance of the 4th quartile worst performing circuits that are in
24 vulnerable communities through our investment programs, Tree Trim, PTMM,
25 Conversion, Customer Excellence, and 4.8kV Hardening. The Company has

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1 identified 191 distribution circuits in vulnerable communities which fall in the
2 fourth quartile for reliability performance based on a five-year historic average.
3 Approximately 55% of the fourth quartile circuits have recently had reliability work
4 performed, while 45% of the circuits are planned to be addressed in 2024-2026
5 investment programs.

6

7 **Q120. What are the Company's future plans to address EJ in the context of**
8 **distribution planning and operations?**

9 A120. DTE Electric plans to continue to analyze reliability and investment data using the
10 draft MiEJScreen tool, including the consideration of any updates based on the
11 state's release of the tool's final version. The company intends continue to include
12 EJ considerations in investment decisions for all areas, as well as continue to
13 address poor performing circuits in vulnerable communities. Finally, DTE Electric
14 will continue to look for potential IJJA grant opportunities that invest in
15 infrastructure-related programs to benefit vulnerable communities in alignment
16 with the Biden Administration's Justice40 initiative.¹³

17

18 **Part XII: Municipal Project Coordination**

19 **Q121. What did the MPSC Case No. U-21297 order the Company to do with regard**
20 **to municipal project coordination?**

21 A121. The Commission stated on page 375 that:

¹³ The White House, Justice40: A Whole-of-Government Initiative, available at: [Justice40 Initiative | Environmental Justice | The White House](https://www.whitehouse.gov/environmentaljustice/justice40/?adlt=strict),
<https://www.whitehouse.gov/environmentaljustice/justice40/?adlt=strict> accessed January 14, 2023.

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1 “In its next general rate case, DTE Electric Company shall demonstrate its efforts
2 to improve communication and coordination with local governments regarding
3 construction activities, as described in this order” (page 375).

4

5 **Q122. How does the Company currently coordinate projects with municipalities?**

6 A122. When DTE is ready to move forward with a capital project the Company
7 coordinates with the appropriate municipal personnel to set up a briefing meeting
8 to discuss the details of the project, benefits, and collaboration opportunities of the
9 work. We request that the municipality provide any potential conflicts to the project
10 before permits are sought. This provides both the municipality and DTE some
11 assurance that the planned project does not conflict with a municipal project,
12 whether it's in the conceptual or planned stage.

13

14 Once the project is in progress, periodic updates are provided to the municipality
15 and meetings may be held work through any questions that arise.

16

17 **Q123. Does the Company have ongoing efforts to improve communication and
18 coordination with municipalities?**

19 A123. Yes. The company is working to improve the frequency of updates to municipalities
20 and garnering feedback to determine their preferred methods to receiving these
21 updates. In addition, we are working with county road commission to support their
22 projects, and to coordinate where possible to avoid conflicts.

23

24 **Q124. Does this complete your direct testimony?**

25 A124. Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21534

REBUTTAL TESTIMONY

OF

ALLEN J. KRYSCYNSKI

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF ALLEN J. KRYSCYNSKI

Line
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1 **Q1. Please state your full name, title, business address and by whom you are**
 2 **employed?**

3 A1. My name is Allen J. Kryscynski (he/him/his), and my business address is One
 4 Energy Plaza, Detroit, Michigan, 48226 and I am employed by DTE Electric
 5 Company

6

7 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
 8 **Company (DTE Electric or Company)?**

9 A2. Yes.

10

11 **Purpose of Testimony**

12 **Q3. What is the purpose of your rebuttal testimony?**

13 A3. The purpose of this testimony is to rebut certain positions of:

14 • Michigan Public Service Commission (MPSC or Commission) Staff (Staff)
 15 Witness Tayler Becker

16 • Attorney General (AG), Michigan Environmental Council (MEC), Natural
 17 Resource Defense Council (NRDC), collectively AG-MN Witness Paul
 18 Alvarez

19 • AG-MN Witness Dennis Stephens

20 • City of Ann Arbor (AA) Witness Melissa Stults

21 • AA Witness Skye Stewart

22 • Michigan Municipal Association for Utility Issues (MAUI) Witness
 23 Richard Bunch

24 • Soulardarity and We Want Green, Too (collectively DAAO) Witness
 25 Elizabeth Jacob

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- 1 • DAAO Witness Yunus Kinkhabwala, PhD
- 2 • DAAO Witness Jackson Koeppel
- 3 • The Ecology Center, The Environmental Law & Policy Center, Union of
- 4 Concerned Scientists, and Vote Solar (CEO) Witness Curt Volkmann
- 5 • CEO Witness Boratha Tan
- 6 • CEO Witness William Kenworthy

7

8 **Q4. Are you sponsoring any exhibits in this proceeding?**

9 A4. Yes. I am sponsoring the following exhibits:

10	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
11	A-43	HH1	MNSCDE-15.23a – Depreciation
12	A-43	HH2	Assessing Changes in the Reliability of the U.S.
13			Electric Power System - LBNL
14	A-43	HH3	Recent trends in power system reliability and
15			implications for evaluating future investments in
16			resiliency
17	A-43	HH4	WP AJK U-21534 GPM
18	A-43	HH5	WP AJK U-21534 Reliability Model
19	A-43	HH6	MNSCDE-12.8b - Reliability Program
20			Analysis

21

22 **Q5. How is your testimony organized?**

23 A5. There are several specific points I will rebut in my testimony; subjects are listed
 24 below. A detailed discussion follows to correct inaccuracies and explain why
 25 certain recommendations should not be accepted by the Commission.

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Rebuttal Content

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1 **Rebuttal Issue 1: System Wide All-Weather Reliability**

2

3 **Q6. What concerns about reliability are expressed by intervenors?**

4 A6. AG-MN Witness Stephens at page 9, lines 8-10, AG-MN Witness Alvarez at page
5 17 line 12, and AA Witness Stults at page 5 line 12 all suggest that all-weather
6 system-wide reliability is not showing an improvement trend, despite recent
7 increases to investment.

8

9 **Q7. Can you please explain why a review of system wide reliability metrics may**
10 **not reflect the investments that are improving sections of the grid?**

11 A7. Yes. When looking at the macro-level, system wide all-weather SAIDI and SAIFI
12 inherently include the volatility of the weather conditions that greatly influence
13 these two reliability measures. When examining these measures narrowly, without
14 taking a longer-term view, reliability is not on a trend that is improving year-over-
15 year. The variability in performance is due in large part to the factors I noted in my
16 revised direct testimony, page 22, Q24, where I discussed three issues summarized
17 here:

18 1) High winds have been increasing over time, causing additional
19 equipment stress and outages.

20 2) Even with the current level of investment, distribution system
21 equipment continues to get older. For example, DTE Electric's wood
22 poles have an average age of approximately 48 years. Furthermore, 32%
23 of poles are over 60 years old, and 10% over 80 years old. Lastly, these
24 older poles are not designed nor built to the current, more resilient
25 construction standards.

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1 3) The Company is early on its journey to stabilize and rebuild the grid.
2 Our strategic capital investment in 2022 was \$715 million, in 2019 it
3 was \$313 million. DTE Electric's distribution system, because of its size
4 and complexity, requires sustained higher levels of investment to affect
5 a change in reliability metrics at an overall system level.

6

7 **Q8. In addition to system-wide all-weather reliability, are there other metrics or**
8 **analysis that should be used to understand the reliability improvements of**
9 **investments, including tree trimming?**

10 A8. Yes. Many of our customers are in fact seeing reliability improvement, in the areas
11 where we have invested. First, as discussed in Q23 of my revised direct testimony,
12 we have seen reliability improvements in the areas that we have tree trimmed and
13 are maintaining tree clearance, and in areas where we have invested in capital
14 infrastructure upgrades. Over multiple rate cases, including this one, the
15 Company's distribution Witnesses have provided rigorous, compelling data
16 analysis to show that these investments are delivering benefits.

17

~~18 As an example of these benefits, communities that have had grid investments are~~
~~19 seeing greater resilience to storms. During the first week of June 2024, the~~
~~20 community of Livonia experienced an EF1 (Enhanced Fujita Scale) tornado with~~
~~21 wind speeds up to 95mph. The area which took the main impact from the tornado~~
~~22 recently had over 200 poles replaced as part of the Pole and Pole Top Maintenance~~
~~23 and Modernization Program (PTMM) program. These upgrades resulted in minimal~~
~~24 damage, including only 3 broken poles, and resulted in a faster restoration effort~~
~~25 99% of customers were restored within 27 hours. On the other hand, an adjacent~~

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~~1 area of the system where PTMM investments have not yet been implemented was
2 also in the path of the storm. In this area the Company experienced 20 broken poles,
3 resulting in over 5,000 customers who had to endure service outages lasting more
4 than 48 hours due to the volume of events and severity damage.~~

5

6 Second, in the 2023 DGP the Company has provided a roadmap of investments and
7 paired that roadmap with a sophisticated reliability model, also provided in this case
8 to support the Company's proposed investments. The reliability model supports the
9 Company's assertion that if the proposed capital investments are made, there will
10 be significant improvements in the Company's non-MED and all-weather
11 reliability metrics.

12

13 **Rebuttal Issue 2: Required Capital Investment**

14

15 **Q9. Please summarize AG-MN Witness Stephens' context for his testimony related
16 to distribution investments.**

17 A9. Witness Stephens (pages 6 line 2 through page 7 line 5) begins his testimony by
18 differentiating what he terms "discretionary" spending from non-discretionary
19 spending. His definition of discretionary is "If the capital is not spent, can
20 customers still have safe and reliable service?" He then proposes that all
21 "discretionary" spending be subject to what he terms "risk-informed benefit -cost
22 analysis".

23

24 **Q10. Do you agree with AG-MN Witness Stephens' definition of discretionary
25 investments?**

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1 A10. No. Merriam Webster¹ provides synonyms of the word “discretionary” that include
2 optional, unnecessary, and unneeded. With his definition, Witness Stephens
3 oversimplifies the planning and scope of investments needed to have a safe,
4 reliable, and accessible grid. He doesn’t provide a timeframe for “safe and reliable
5 service”, and his definition could be interpreted as only considering the current,
6 immediate grid condition, instead of planning ahead for future reliability or safety
7 risks. This would be similar to determining whether or not to replace aged, worn
8 tires on a car. The tire replacement using his definition is discretionary, right up
9 until the moment when the tire skids on wet pavement, a safety concern, or blows
10 out while driving on a highway, a safety and reliability concern. Witness Stephens’
11 also fails to account for the fact that in-service failures, be it car tires or electrical
12 equipment, are typically far more costly than carefully planned investment.

13

14 **Q11. Do other Witnesses adopt AG-MN Witness Stephens’ use of what they view as**
15 **discretionary vs non-discretionary investments?**

16 A11. Yes. AG-MN Witness Alvarez on page 14 lines 1-5 of his direct testimony notes
17 that “... almost all of the projects within these [strategic capital] programs are
18 discretionary as to timing and extent. This means that none are required to address
19 equipment failures or equipment damage; or connect new customers; or
20 accommodate near-term load increases”

21

22 **Q12. Do you agree that the strategic capital programs AG-MN Witness Alvarez**
23 **claims are discretionary programs do not address “equipment failures and**
24 **equipment damage”?**

¹ “Discretionary.” *Merriam-Webster.com Thesaurus*, Merriam-Webster, <https://www.merriam-webster.com/thesaurus/discretionary>. Accessed 14 Aug. 2024.

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1 A12. No, Witness Alvarez' statement is incorrect. For example, as discussed by Witness
2 Elliott-Andahazy in her revised direct testimony, the purpose of the PTMM
3 program is targeted at replacing failed or damaged equipment. This includes broken
4 cross arms, poles that have failed strength tests, cracked/broken insulators,
5 crack/broken fuse cutouts, and blown fuses. Subtransmission projects, and
6 conversion projects discussed by Witness Deol in his direct testimony replace this
7 same type of equipment in the course of construction as well, with additional work
8 included. Additionally, programs including PTMM, Breaker Replacement, System
9 Cable, and URD target equipment replacements that have either failed in the past
10 or have known high failure rates and are expected to fail again in the near future.
11 Please reference Witness Elliott-Andahazy's revised direct testimony, Figure 7, for
12 visual examples of broken equipment that is typically replaced when identified as
13 part of the PTMM inspection.

14

15 **Q13. As an alternative to AG-MN Witness Stephen's "discretionary" and "non-**
16 **discretionary" definitions, is there a broader industry-recognized standard to**
17 **evaluate segregations of utility investments?**

18 A13. Yes. The Department of Energy (DOE) in its DSPx model segregates utility grid
19 investments into "core components" and "applications." Core components
20 comprise the essential technologies that provide a foundation for a modern
21 distribution system, while applications represent the various additional
22 technologies that can layer on top of core components to add additional
23 functionality to the grid.
24 The DOE in its DSPx model states that "core distribution cyber-physical and
25 operational platform components include:

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- 1 • Physical infrastructure (e.g. wires, transformers, switches, etc.)
- 2 • Advanced protection and controls
- 3 • Sensing and situational awareness
- 4 • Operational communications
- 5 • Planning tools and models (e.g., DER & load forecasting, power flow analysis,
- 6 etc.)

7 These components comprise the essential technologies that provide a foundation
8 for a modern distribution grid. DOE’s Modern Grid Initiative², EPRI’s research³
9 and others over the past 15 years have consistently identified these five categories
10 as core or foundational components of the grid.”⁴

11

12 **Q14. Is it your understanding that the criterion that the Commission uses to**
13 **determine if an investment proposed by a utility should be included in rate**
14 **base for the purpose of cost recovery is whether that investment is**
15 **“discretionary” or “non-discretionary”?**

16 A14. No, it is my understanding that the MPSC approves investments proposed by a
17 utility for cost recovery in rates if the Commission determines that the investments
18 are reasonable and prudent as well as other considerations.

19

20 **Q15. What other concern does AG-MN Witness Alvarez have regarding the need**
21 **for equipment replacements to improve grid reliability?**

² U.S. Department of Energy. Grid Modernization Initiative, 2017

³ Electric Power Research Institute. Needed: A Grid Operating System to Facilitate Grid Transformation. July 2011. Available online:

https://www.smartgrid.gov/files/documents/Needed_Grid_Operating_System_to_Facilitate_Grid_Transformation_201108.pdf, accessed August 6, 2024

⁴ Next-Generation Distribution System Platform Initiative (DSPx) Modern Distribution Grid Volume I – Strategy and Implementation Planning, page 25, available at <https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid-Volume-III.pdf>, accessed August 6, 2024

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- 1 A15. On page 17, lines 10-12, he quotes the 2023 Distribution Grid Plan (DGP):
- 2 “much of the current infrastructure is at or beyond *expected*
- 3 *useful life* and susceptible to failure, particularly when
- 4 exposed to extreme weather” (emphasis added)
- 5 then goes on to say on page 17 line 12 through page 18 line 2:
- 6 “This statement contains several misleading statements.
- 7 First, “*expected useful life*” is a reference to *depreciation*
- 8 *periods*, which are based on the average age of assets in
- 9 service” (emphasis added),
- 10 and then concludes on page 18, lines 8-10:
- 11 “To decide that equipment should be replaced simply
- 12 because it is *fully depreciated*, when decades of useful life
- 13 might be remaining, serves shareholders at customers’
- 14 expense.” (Emphasis added).
- 15 **Q16. Is AG-MN Witness Alvarez correct in his assertion that equipment is replaced**
- 16 **“simply because it is fully depreciated”?**
- 17 A16. No, for two reasons. Witness Alvarez misunderstands the criteria the Company uses
- 18 when assessing the need to replace equipment. First, he is incorrect in his
- 19 assumption that the Company’s use of the term “expected useful life” is a reference
- 20 to depreciation periods. In discovery response MNSC 15.23a, Exhibit A-43
- 21 Schedule HH1 - MNSCDE-15.23a – Depreciation, when asked to confirm that the
- 22 Company uses the terms “useful life” and “depreciation period” interchangeably,
- 23 Company Witness Elliott Andahazy responded “Not confirmed.” She then clarified
- 24 that the Company uses depreciation rates for the purpose of calculating depreciation
- 25 expense.
- 26
- 27 Secondly, in my revised direct testimony, on page 17, lines 1 through 16, I describe
- 28 that the Company’s subject matter experts use many factors when determining

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1 equipment expected life expectancy, which is used in estimating investment needed
2 for equipment replacements. I further describe that equipment age, but not
3 depreciation status, is just one of the factors considered to assess asset health and
4 the need for replacement.

5

6 **Q17. Does equipment depreciation status factor into the Company's distribution**
7 **equipment replacement decisions?**

8 A17. No.

9

10 **Rebuttal Issue 3: Equipment Outages**

11

12 **Q18. Witness AG-MN Stephens, in addressing what he believes to be the cause of**
13 **outages, makes the statement that “storm response and vegetation**
14 **management – not equipment condition – have driven the Company's**
15 **historically poor (relative to peers) reliability performance”.⁵ Similarly**
16 **Witness Alvarez says “Given that vegetation contact is the root cause of at least**
17 **50% of the interruption minutes customers experience, spending should be**
18 **focused on root causes.”⁶ Do you agree with Witness Alvarez and AG-MN**
19 **Witness Stephens' characterization of the key drivers of reliability?**

20 A18. I agree that vegetation is a significant cause of outages, which is why the Company
21 began the Tree Trim Surge program in 2019. However, I believe that focusing
22 solely on vegetation would not by itself address the complex set of factors that
23 influence distribution reliability.

24

⁵ Stephens DT page 7, lines 19-20

⁶ Alvarez DT, page 19, lines 12-14

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1 **Q19. Can you provide more detail on what you call the complex set of factors that**
2 **influence distribution reliability?**

3 A19. Yes. The full analysis of grid reliability needs to address both the initiating event
4 that caused the outage (i.e., trees/wind) and the underlying equipment that was not
5 resilient to trees/wind. As an example, on a circuit which is on-cycle for tree
6 trimming could have an out of right of way tree that falls into the lines. When this
7 happens, whether an outage occurs or not, the size of the outage, and the extent of
8 damage is determined in part by the equipment that the tree encounters. If the
9 equipment is aged or built to a previous less-robust engineering and construction
10 standard, the tree will be more likely to break the equipment. However, if the circuit
11 has been rebuilt to the current stronger standard, with larger poles, fiberglass cross
12 arms, and steel reinforced wire, the equipment may not fail or the damage will be
13 minimized. Additionally, automation investments will provide even more
14 improvements to reliability. Using a similar example, if high winds cause a large
15 branch to create an outage and an automated recloser loop scheme is installed on
16 that circuit, not only will the outage be reduced in size (number of customers
17 affected) but the Company will have information on specifically where the outage
18 occurred, which will allow the Company to dispatch crews directly to the location
19 without the need to patrol the circuit. A more detailed description of automation
20 benefits can be found in Witness Hartwick's revised direct testimony on pages 11
21 through 12.

22

23 **Q20. Do you agree with AG-MN Witness Stephens' characterization of the**
24 **Company's "storm response" as a key driver impacting reliability**
25 **performance?**

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1 A20. No. The Company has storm processes in place that allow the Company to mobilize
2 and respond quickly to storms, and the Company continues to evaluate and improve
3 its storm response processes. Witness Stephens fails to account for the real issue
4 impacting “storm response” which has been, and is still today, the volume of events
5 that occur during a narrow window of time during large weather events. During
6 these storms, the Company typically has significantly more outage events than line
7 crews to assign to mitigate the events due to the amount and complexity of damage
8 that occurs. Even with the additional support of foreign crews, restoration can
9 become a supply vs. demand problem. And while the Company has made
10 improvements to increase the supply of lineman, the Company must also reduce the
11 demand for linemen, meaning the need to reduce the number of outage events by
12 hardening the grid in order to continue to mitigate and fully solve this problem. In
13 summary, the storm response challenges are primarily driven by event volume, in
14 part, by equipment that is no longer capable of standing up to increasingly harsh
15 weather conditions.

16

17 **Q21. Based on his interpretation of DTE Electric’s reliability data, what are AG-**
18 **MN Witness Alvarez’s conclusions and recommendations?**

19 A21. Witness Alvarez’s conclusion is equipment related failures are not a significant root
20 cause of outages, and that capital programs such as automation, which admittedly
21 improve reliability by reducing the impact of outages, are not an effective approach
22 to improve reliability (page 19, lines 8-15). He also recommends that the
23 Commission:

24 “Require DTE to slow the rate of capital spending and assess
25 the benefits of its vegetation management program relative
26 to strategic capital spending aimed at improving reliability.”
27 (Alvarez, page 8, lines 9-11)

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1 **Q22. Does AG-MN Witness Alvarez reference any studies to support his conclusion**
2 **that capital investment should be slowed?**

3 A22. Yes. On page 16, lines 4-6, Witness Alvarez says:

4 “Research completed by Lawrence Berkeley National
5 Laboratory on behalf of the U.S. Department of Energy
6 found no correlation between investor-owned utility
7 distribution capital spending increases and reliability
8 improvement the following year.”

9 The study cited in his testimony at the bottom of page 16 is “Assessing Changes in
10 the Reliability of the U.S. Electric Power System. Lawrence Berkeley National
11 Laboratory report LBNL-188741 (August 2015), pp. 37-38.”

12

13 **Q23. Is AG-MN Witness Alvarez’s correctly interpreting LBNL’s research that**
14 **there is no correlation between capital and reliability improvements accurate?**

15 A23. No. Witness Alvarez’s conclusion there is no correlation between capital
16 investment and reliability improvements is incorrect. In fact, it’s impossible given
17 the inputs into the study. The LNBL study, included as Exhibit A-43, Schedule
18 HH2⁷ - Assessing Changes in the Reliability of the U.S. Electric Power System -
19 LBNL, talks about spending in terms of "maintenance" (O&M). The O&M spend
20 that was analyzed was not only distribution O&M but bundled to include
21 transmission O&M dollars. Capital investment was not analyzed in this study. A
22 subsequent journal article published by the authors, Exhibit A-43, Schedule HH3 –
23 “Recent trends in power system reliability and implications for evaluating future
24 investments in resiliency”, is even more precise in defining spending as "T&D
25 O&M expenditures".

26

⁷ Exhibit A-43, Schedule HH2 page 17

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1 **Q24. Did the LBNL study conclude there was no correlation between O&M**
2 **spending and reliability the following year?**

3 A24. No, in fact this journal article indicates that 10 of the 12 models evaluated had a
4 negative sign for the expenditures variable as summarized in Tables A.4 and A.5 in
5 Schedule HH3, although many were not statistically significant. The negative sign
6 means that previous year O&M spending is correlated with an improvement in
7 reliability (SAIDI+SAIFI) the following year.

8

9 **Q25. What concerns does AG-MN Witness Stephens have about the impact of**
10 **equipment failures on reliability?**

11 A25. Witness Stephens performed an analysis on a small set of outage events and claimed
12 that the percentage of interruptions caused by equipment is small – less than 12%.
13 (Page 8, lines 5-10)

14

15 **Q26. Does the Company have concerns with AG-MN Witness Stephen's analysis?**

16 A26. Yes, the Company has two main concerns. The first is that the Company was unable
17 to verify Witness Stephens' analysis. He claims he examined 100 service
18 interruptions with the cause of 'equipment failure' (page 8, line 7), however the file
19 provided only included 77 events with the cause of 'equipment failure' and only 68
20 indicated any analysis had been done. The second, and more important concern
21 regarding Witness Stephens' analysis is that he relied on outage crew field notes
22 provided by the Company to determine if equipment caused the outage. Field notes
23 are not intended to document the cause of outages, rather they are used in the
24 moment as a means of communication between various field resources and the
25 systems operations center to co-ordinate and facilitate restoration. The primary

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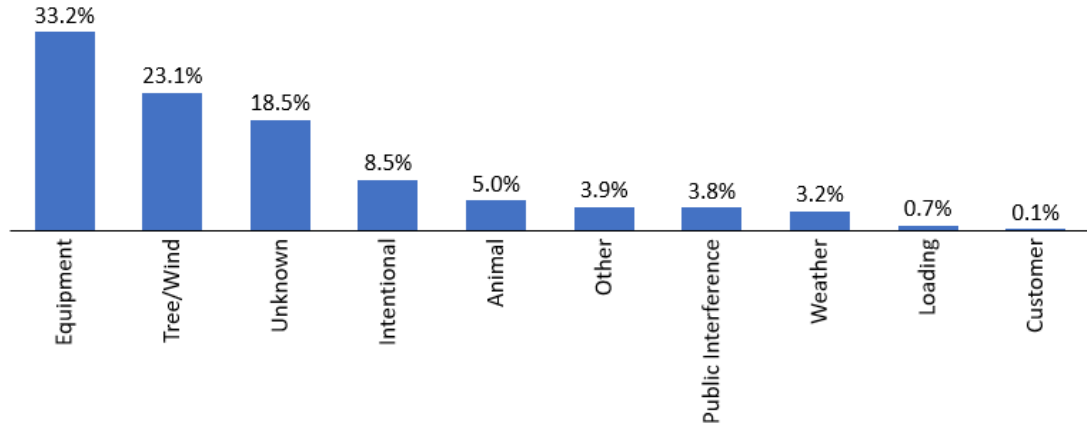
1 indicator of the cause of the outages is the cause code field in the outage
2 management system.

3

4 **Q27. What analysis has the Company performed to estimate the cause of outages?**

5 A27. The Company has calculated the percentages of customer interruptions, by cause
6 code, under non-MED conditions over the past five years. The results, by cause
7 code, are shown in Figure 1 below. The cause code 'Equipment Failure' is the
8 largest contribution to customer interruptions, followed by tree/wind related events.
9 The conclusion from this analysis is that equipment is indeed a leading cause of
10 outages, and the tree trimming program, while important to address tree related
11 outages, is not sufficient to address a significant portion of outages.

12 **Figure 1 Customer Interruptions by cause code (2019-2023, Non-MEDs)**



13

14 **Q28. Do you agree with Witness Alvarez's recommendation to slow capital**
15 **spending⁸ to assess benefits of its tree trim program relative to its capital**
16 **program?**

17 A28. No. There are several reasons why I disagree:

⁸ Alvarez DT, p. 8, lines 9-11

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- 1 1) Customers are clear that they want to see significant reliability
2 improvements even in the face of storms.
- 3 2) With 90%⁹ of the system on cycle for Tree Trimming by the end of
4 2024, the Company’s reliability model indicates that the two largest
5 opportunities to improve reliability are Circuit Automation¹⁰ and
6 replacing degraded equipment (PTMM, Hardening, Conversion), which
7 will account for almost 80% of the projected all-weather SAIDI
8 improvements by 2029. Delaying this work will hamper the Company’s
9 ability to improve customer reliability in the near-term.
- 10 3) The majority of our customer interruptions are not tree related.¹¹
- 11 4) The benefits of the Tree Trim program are well known, and analysis has
12 been presented in this rate case, past rate cases, and annual tree trim
13 reports submitted to the Commission for years.
- 14 5) While the Company’s Tree Trim program has proved highly effective,
15 the Company’s recent reliability performance shows that more capital
16 infrastructure investment is needed.

⁹ See Witness Steudle testimony, page 15, line 14

¹⁰ As Witness Alvarez notes on page 19, lines 10-12, DTE Electric’s Distribution Automation program is “designed to mitigate the impact of service interruptions.”¹¹ Data in the 2023 DGP shows that 69% of all-weather SAIFI and 50% of all-weather SAIDI is from causes other than trees. See Exhibits 4.2.2.1 and 4.2.2.2 within the 2032 DGP, (Exhibit A-23, Schedule M8)¹² Order in U-21297 filed on 12/1/2023 available at <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000At0VBAAZ>.

¹¹ Data in the 2023 DGP shows that 69% of all-weather SAIFI and 50% of all-weather SAIDI is from causes other than trees. See Exhibits 4.2.2.1 and 4.2.2.2 within the 2032 DGP, (Exhibit A-23, Schedule M8)¹² Order in U-21297 filed on 12/1/2023 available at <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000At0VBAAZ>.

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1 **Rebuttal Issue 4: Capital Investment Governance**

2

3 **Q29. What concerns does AG-MN Witness Alvarez have related to the Company's**
4 **strategic capital investment governance?**

5 A29. AG-MN Witness Alvarez first divides distribution capital investments into defined
6 capital projects and strategic capital programs. He finds no deficiencies in defined
7 capital projects, and in fact provides an appropriate summary of the capital project
8 process. (page 27, lines 5-7) For strategic capital programs however, he notes
9 perceived deficiencies in the Company's planning and cost tracking, which is how
10 he defines governance (page 27, lines 7-9).

11

12 **Q30. What does AG-MN Witness Alvarez believe are deficiencies in the planning**
13 **and cost tracking of the Company's strategic capital investment programs?**

14 A30. On page 27, lines 11-12, Witness Alvarez specifically calls out the PTMM,
15 Hardening, Distribution Automation (DA) programs and notes that these programs
16 "appear to be managed only at the program level as opposed to project level." He
17 appears to arrive at this conclusion because he was unable to find annual program
18 goals for units such as circuit miles or DA devices, what he calls "established
19 expectations". (page 27, line 15 – page 28, line 2).

20

21 **Q31. Has the Company provided units for strategic capital programs in**
22 **documentation in the instant case?**

23 A31. Yes. I'll provide two examples, for programs he referenced in his testimony.
24 First, for DA, Witness Hartwick on page 19 of her revised direct testimony, Q33,
25 identified the DA plan for 2024, which included infrastructure recovery mechanism

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1 (IRM) related work for 63 circuits and a total of 189 recloser devices, and an
2 additional 32 circuits with 96 recloser devices for the 4.8kV system. She further
3 identified the 2024 engineering and design work for recloser devices that would be
4 installed on circuits in 2025, 240 reclosers on approximately 80 circuits.

5
6 As a second example, for the PTMM program, Witness Elliott Andahazy on page
7 53, table 12 of her direct testimony, provides the program goals in 2024 and 2025.
8 For 2024, the program goals include 750 circuit miles, 1,700 pole replacements,
9 and 8,655 pole top replacements, for a program cost of \$63,450,000. In addition to
10 direct testimony, the Company Distribution Witnesses provided copious details
11 related to program and project units in discovery.

12

13 **Q32. Does AG-MN Witness Alvarez have any other concerns related to strategic**
14 **capital program governance?**

15 A32. Yes. Stemming from his concern about planning and cost tracking related to
16 established expectations for units, he believes that this can lead to an inability to
17 track program improvements (page 28, line 1), which he also reiterated when he
18 said “program benefit projections can be over-estimated” (page 28, line 7).

19

20 **Q33. Do you agree with AG-MN Witness Alvarez’s conclusions related to tracking**
21 **and the potential over-estimating of program benefits?**

22 A33. No. As I discussed above, the Company can and does have annual goals for
23 program units achieved, which is the basis of his concern. Additionally, Company
24 Witnesses Hartwick and Elliott Andahazy cover the benefits of their programs, and
25 the Company’s reliability model where the program benefits are modeled.

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1 **Rebuttal Issue 5: Benefit Cost Analysis**

2

3 **Q34. What feedback was provided by the Commission and other stakeholders**
4 **regarding the previous version of the Global Prioritization Model (GPM) and**
5 **Benefit Cost Analysis (BCA), and use of the DGP in supporting rate case**
6 **investments in their order in Case No. U-21297 (the Company’s prior rate**
7 **case)?**

8 A34. The Commission wrote the following regarding the GPM, the DGP, and how the
9 Company prioritizes its investments on p71¹²:

10 1) “The Commission notes that DTE Electric presented the GPM and
11 the DGP as the sole sources of support for many capital expenditure
12 programs in the distribution category”

13 2) “The Commission requires greater transparency into the basis for
14 the GPM”

15 3) “To the extent that either the GPM or the DGP offers a facsimile of
16 a BCA, costs are not always addressed and benefits are not always
17 quantified”

18

19 **Q35. Did the Company provide additional sources of support for distribution**
20 **investments in this case?**

21 A35. Yes, there are at least three additional sources of support for distribution
22 investments in the instant case. The first is the level of detail on both project
23 purpose, scope and benefits in the capital summaries (Exhibit A-23, Schedules M5,
24 M6, and M7). Secondly, the Company developed a new BCA methodology for two

¹² Order in U-21297 filed on 12/1/2023 available at <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000At0VBAAZ>.

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1 investment areas, PTMM and Undergrounding, and provided these BCA
2 spreadsheets and calculations as part of the case. Finally, the Company developed
3 a more comprehensive, circuit-level, reliability model to help tie potential
4 investments in six key investment areas (Tree Trimming, 4.8kV Hardening,
5 PTMM, Customer Excellence, Distribution Automation, and 4.8kV Conversion) to
6 future reliability improvements.

7

8 **Q36. How did the Company provide more transparency into the basis for GPM?**

9 A36. The Company submitted a working version of the GPM as a workpaper in this case,
10 which included all the assumptions and underlying data on project and program
11 costs and benefits. The Company also submitted the Reliability Model as a
12 workpaper which includes a bottoms-up, circuit level projection of reliability
13 impacts for the six programs mentioned above. Additionally, supporting
14 documentation and analysis for both models was provided throughout the discovery
15 process. Those workpapers are included as Exhibits A-43, Schedule HH4 - WP
16 AJK U-21534 GPM and A-43 Schedule, HH5 - WP AJK U-21534 Reliability
17 Model.

18

19 **Q37. Does the Company plan to continue to enhance and improve the methods used
20 to evaluate projects and programs, including quantified benefits?**

21 A37. Yes, the Company intends to further enhance its already strong investment analysis
22 supplemented by the latest BCA presented in this case. It is worth noting that not
23 every grid/reliability investment can be effectively translated into a monetized
24 valuation as the sole basis for the investment decision making process. The
25 Company is committed to explore further improvements in support of the less

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1 tangible benefit criteria such as safety and resiliency in order to further enhance the
2 GPM and support the need for additional investment in the grid. At this time, it is
3 the Company's intention to incorporate additional refinements of the investment
4 analysis process into its next rate case.

5

6 **Q38. Is it reasonable to adopt AG-MN Witness Alvarez's recommendation (page 49,**
7 **lines 15-16) to utilize a risk-informed benefit cost analysis, similar to the one**
8 **used in California, for the next DGP or rate case?**

9 A38. No. Witness Alvarez proposes using the risk-informed decision-making (RIDM)
10 framework, such as what California uses for its safety investments that are primarily
11 intended to address large scale risks such as wildfires and the associated Public
12 Safety Power Shutoffs (PSPS), catastrophic earthquake, hydro dam failures, cyber-
13 attacks on the critical energy infrastructures, and other potential public safety risks.
14 Witness Alvarez's testimony omits the history of the long journey that evolved
15 from the initial Safety Model Assessment Proceeding (S-MAP) that started nearly
16 a decade ago in parallel with the Risk Assessment and Mitigation Phase (RAMP)
17 proceedings as the precursor to their General Rate Case proceedings. By its own
18 account, the California Public Utility Commission's staff shared in its report that:

19 "…the RDF's [Risk-based Decision Making Framework]
20 decade in existence notwithstanding, a substantial amount of
21 work remains to be done to seamlessly integrate the risk-
22 based decision-making framework into utility General Rate
23 Cases. At present, the rapid clip at which utility safety-
24 related risk mitigation expenditures are growing points to an
25 unsustainable trend."¹³

26

¹³ https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/paper_final_june_2022_cpuc_rdf_crri.pdf, page 13

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1 In studying the historical evolution of California’s RAMP filings, and specifically,
2 this methodology for evaluating safety and reliability plans, the Company draws
3 the following conclusions:

4 1) The framework has been developed over the course of a decade and has
5 evolved through many iterations.

6 2) The development has been led by the California PUC and based on joint
7 working sessions between the utilities.

8 3) The framework is applied to all large IOUs in the state.

9 4) The framework is very complex and has both quantitative and qualitative
10 metrics.

11

12 It would not be reasonable to adopt another state’s risk-informed cost-benefit
13 analysis in a short period of time and without due diligence, which would omit the
14 opportunity to tailor the framework to the unique needs of the state of Michigan.

15

16 **Q39. Does the information in this instant case provide a reasonable and prudent**
17 **method for evaluating investments?**

18 A39. Yes, even as the Company works through BCA enhancements for future DGPs and
19 rate cases, the information submitted in this instant rate case provides a holistic
20 view of both project benefits and costs that support the Company’s proposed
21 investments. Furthermore, the GPM is a sound method for evaluating the relative
22 benefits of different investments on safety, reliability, capacity, and equity.

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1 **Rebuttal Issue 6: Global Prioritization Model (GPM)**

2

3 **Q40. What concerns does AG-MN Witness Alvarez express regarding the**
4 **Company's GPM model?**

5 A40. Witness Alvarez's concerns are:

6 1) The GPM does not answer the "important questions" about selecting
7 strategic investments (page 45, lines 8-13)

8 2) The GPM is "subjective" and is "not data-driven" (page 46, lines 1-3, 12-
9 14)

10 3) Failing to include the tree trimming program in the GPM is problematic
11 (page 48, lines 1-6)

12 4) GPM evaluates both projects and programs together (page 47, lines 15-22)

13 5) GPM scores can be manipulated (page 46, lines 15-17)

14 6) GPM does not provide a "baseline" for reference (page 46, lines 4-12)

15

16 **Q41. Does the Company agree that AG-MN Witness Alvarez's concerns have a**
17 **material impact on the model's ability effectively support capital investments?**

18 A41. No. The Company disagrees with each of these claims in whole or in part, as well
19 as his recommendation to question the use of the GPM based on those claims. Each
20 concern will be discussed in turn below.

21

22 **Q42. What does AG-MN Witness Alvarez believe are the important questions the**
23 **GPM should answer?**

24 A42. The first concern is whether the GPM answers the "important questions" he asked
25 about grid investments. As stated on page 45, lines 8-12 of Witness Alvarez's
26 testimony: "There are important questions to be answered when making decisions

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1 about discretionary investments. These include 1) Do the benefits to customers
2 from the project or program exceed the program's costs to customers? 2) For
3 programs, what is the optimum geographic extent of deployment (i.e., on which
4 circuits or in what circumstances are the benefits more likely to deliver benefits in
5 excess of costs)? and 3) For programs, what is the optimum timing/deployment
6 speed?"

7

8 **Q43. Does AG-MN Witness Alvarez provide any support as to why these three**
9 **specific questions are required to be answered by the GPM or any investment**
10 **support tool?**

11 A43. No. There is no citation or reference as to whether these questions, and not other
12 questions, should be part of a standard decision-making process employed in
13 distribution planning, or if they were developed with any discussion with the
14 Commission, the utility, or other stakeholders. In some cases, the questions may
15 not even be applicable. For the PTMM program, for instance, there is no planned
16 geographic boundary for its extent as the best utility practice would be to inspect
17 all poles in the entire system.

18

19 **Q44. What is the basis of the Company's process for evaluating strategic**
20 **distribution investments?**

21 A44. As discussed in both the 2021 DGP and 2023 DGP, and mentioned briefly in
22 testimony above, the Company utilizes the Department of Energy (DOE) DSPx grid
23 modernization framework as part of the planning process. The first step of the
24 planning process is to define the objectives for grid investments.¹⁴

¹⁴ *Modern Distribution Grid (DSPx)*. (2019 November) Pacific Northwest National Lab. [Modern-Distribution-Grid Volume I v2 0.pdf \(pnnl.gov\)](#)

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1 **Q45. How did the Company define the objectives for distribution investments?**

2 A45. The Company adopted its planning objectives of 1) Safe, 2) Reliable and Resilient,
3 3) Affordable, 4) Customer Accessibility and Community Focus, and 5) Clean.
4 These were developed to be aligned with the objectives the Commission stated in
5 Case No. U-20147¹⁵. The Commission's objectives are Safety, Reliability and
6 Resilience, Cost Effectiveness and Affordability, and Accessibility. The GPM
7 measures project benefits across ten dimensions which are mapped to DTE
8 Electric's five planning objectives as was discussed in my revised direct testimony
9 on page 57 (Table 6) and is also provided below as Table 1 for convenience. The
10 benefits included in the GPM were selected not only because they meet a grid or
11 customer need, but also because they align with the overall objectives for the grid.
12

13 **Table 1 GPM Impact Dimensions and Planning Objectives**

		Planning Objectives				
		Safe	Reliable and Resilient	Affordable	Clean	Customer accessible and community focus
GPM Impact Dimensions	Reduce Electrical Hazards	✓		✓		
	Overload Relief	✓	✓	✓	✓	✓
	SAIDI	✓	✓	✓		
	SAIFI		✓			
	Regulatory Compliance	✓	✓			
	Major event risk	✓	✓	✓		
	Capacity Relief		✓		✓	✓
	Investment in EJ communities					✓
	O&M Avoidance			✓		
	Capital Avoidance			✓		

14

¹⁵ August 20, 2020 Commission order in U-20147, pp 36-38 ([mi-
psc.my.site.com/sfc/servlet.shepherd/version/download/068t000000DcfWRAAZ](https://psc.my.site.com/sfc/servlet.shepherd/version/download/068t000000DcfWRAAZ))

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1 **Q46. AG-MN Witness Alvarez states that “DTE’s GPM purports to rank capital**
2 **projects and programs based on their ability to reduce risk, from highest to**
3 **lowest.”¹⁶ Is this an accurate assessment of the GPM model?**

4 A46. No. The Company characterizes the impact dimensions used in the GPM as benefits
5 to the customer or grid. Some dimensions, such as “major event risk”, do measure
6 risk. The Company does not characterize the other benefits projects bring, such as
7 improved reliability, additional capacity, investment in environmental justice (EJ)
8 communities, and reduction of reactive cost as ‘risk reduction’.

9

10 **Q47. Do the set of impact dimensions included in the GPM lead to problematic**
11 **overlapping or double counting of benefits, as AG-MN Witness Alvarez**
12 **states¹⁷?**

13 A47. No. The specific impact dimensions Witness Alvarez references, “overload relief”
14 and “capacity relief” do not double count. “Major event risk”, “SAIDI”, and
15 “SAIFI” measure different aspects of customer reliability.

16

17 **Q48. Does the GPM double count benefits related to loading and capacity as AG-**
18 **MN Witness Alvarez claims?**

19 A48. No, these “overload” and “capacity” metrics were explained in the 2023 DGP in
20 Section 12.1. “Overload” refers to equipment which will operate above its rating
21 during peak loading under normal conditions. For example, a cable serving a circuit
22 has a measured load at peak that exceeds the capacity of that cable. “Capacity”
23 measures capacity constraints that exist in the event of a failure and include
24 substations operating over firm or violations of subtransmission planning criteria.

¹⁶ Alvarez DT, p. 45, lines 15-16

¹⁷ Alvarez DT, p. 45, lines 21-23

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1 For example, in a two-transformer substation, both transformers could be operating
2 under their ratings in normal circumstances and would not have an ‘overload relief’
3 score, however, in the event of a transformer failure, if the other transformer is
4 unable to serve the entire substation on its own, it would receive a “Capacity” score,
5 assuming the project in the GPM corrected the capacity concern.

6

7 **Q49. Do the GPM dimensions related to reliability and major event risk measure**
8 **different things?**

9 A49. Yes. “Major event risk”, “SAIDI”, and “SAIFI” dimensions all serve different
10 purposes. Major event risk provides a framework to prioritize investment that
11 would avoid large outages from substations failures. SAIDI and SAIFI
12 improvements are mostly aligned with reducing outages on circuits (overhead
13 outages and URD outages). Additionally, the Company added SAIFI to the GPM
14 in this iteration to complement SAIDI and provide a more complete picture of the
15 reliability experience. Some customers may experience a few long duration outages
16 which would be reflected by SAIDI improvements. Others may experience short
17 but frequent outages which would be reflected by SAIFI improvements. Both
18 duration and frequency measurements are relevant to customer reliability.

19

20 **Q50. How does AG-MN Witness Alvarez characterize the data used to calculate**
21 **GPM scores?**

22 A50. His second concern is the claim that “most of these inputs are not data-driven (i.e.,
23 based on historical experience, research or pilot results), but based on subjective

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1 GPM user assessments”.¹⁸ In addition, he states that “subjective inputs outweigh
2 data-driven inputs”.¹⁹

3

4 **Q51. Is this an accurate assessment of the inputs to the GPM?**

5 A51. No. The Company would classify information in the GPM as either a) “objective”
6 or b) “based on subject matter expertise”. Objective data is based on a measurement
7 or observation and would not generally require any additional judgement or input.
8 Examples of this type of data are reliability data (SAIDI and SAIFI), wiredown
9 data, loading data, equipment ratings, event volume, and historical costs per event.
10 Other scoring may fall into the latter category and be based on the assessment of
11 people with specific expertise in the field.

12

13 **Q52. How would the Company classify the data used in the GPM?**

14 A52. The Company would classify the inputs shown in Table 2 below as primarily
15 objective.

16

Table 2 Classification of GPM Inputs

17

Objective Inputs

- Historical reliability performance
- Historical wiredown performance
- Loading data
- Equipment ratings
- Stranded load calculations
- Demographic data such as inputs to the MiEJ Screen tool
- Historical trouble event volume
- Historical average costs per event
- Projected improvements in reliability, event volume, etc

Inputs based on subject matter expertise

- Scoring methodologies which combine multiple elements into a single value such as:
 - Asset health ratings
 - Load relief ratings
 - Overall MiEJ Screen score
- Assessment of whether investment meets regulatory compliance goals

18

¹⁸ Alvarez DT, p. 46, lines 2-3

¹⁹ Alvarez DT, p. 46, lines 12-13

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1 **Q53. What is an example of an input based on subject matter expertise?**
 2 A53. Asset health assessments and scoring frameworks to rate key pieces of distribution
 3 equipment can be based on subject matter expertise. An example of how the various
 4 types of switchgear on the DTE Electric system are scored by equipment engineers
 5 is shown below in Figure 2 and were provided in discovery. The Company’s
 6 equipment engineers, who have decades of experience operating, maintaining, and
 7 repairing DTE Electric’s equipment identified the key aspects of switchgear which
 8 have historically caused issues. The experts in this field have identified nine
 9 different criteria which reflect previous challenges with the equipment, and assign
 10 scoring based on their judgement of the likelihood and severity of failure. The fleet
 11 of 250 switchgear lineups is scored based on this consistent methodology. Note,
 12 that while this method is subjective, it is quantitatively based.

14 **Figure 2 Switchgear Asset Health Scoring**

Inputs (to the raw score):			
DESIGN TYPE	DESIGN TYPE Score	NO SPARE PROPERTY	Asbestos Control Wiring
Across-the-Aisle	5	Yes 0	Yes 1
Single-Bus, Single Row (Outdoor Truck)	5	No 2	No 0
Transfer Bus/Aisleway	4		
Single-Bus, Two-Feeder	0	AGE	Age Score
Single-Bus, Single Row/PDC	0	0 0	
Double-Bus, Two-Tier w/o PDC	1	10 0	
Double-Bus, Two-Tier/PDC	0	20 0	
Single Feeder	4	30 2	
		40 3	
Year		50 4	
2015		60 5	
		70 6	
Number of CALVERT BUS	CALVERT BUS Score	PARTS	No Parts Score
0	0	Spare Parts Available	0
1	1	No Spare Parts	3
2	2		
Breaker Racking		PREVIOUS FIRE	
Open Door	1	Yes 3	
Closed Door	0	No 0	
OPERATING ISSUES		Each of these categories are summed for their respective switchgear to develop the overall raw score.	
Yes	6		
No	0		
			Total Risk Score = Modified
			*Time to Repair Score = All have a score of 12 due to t wh
			Last Data update: 2/3/2021
			High Asset score 10 or above
			Westinghouse
			Cornel - ITE 15HK250
			Elevated Asset score 1-9
			Acceptable Asset score 0
			Total Plant:

15
 16 **Q54. What is the Company’s assessment of the use of objective versus subject**
 17 **matter expert inputs to the model?**

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1 A54. Table 3 below is an analysis of all 138 projects scored in the GPM, with the total
2 score by dimension and the total score for all evaluated projects shown. The five
3 bolded dimensions (Reduce Electrical Hazards, SAIDI, SAIFI, O&M Avoidance
4 and Capital Avoidance) are entirely calculated based on objective information and
5 contribute 45% of the overall scoring. If we include the Investment in EJ
6 Communities dimension, which uses the MiEJ Screen score for the investment area
7 and was developed by the Department of Environment, Great Lakes and Energy
8 (EGLE), and contributes 18% to the total, 63% of the total scoring in the GPM is
9 objective. The dimensions that include some subject matter expertise, such as
10 Overload Relief and Capacity Relief, are also based on objective inputs such as
11 measured load and equipment ratings. In short, the Company's analysis of the data
12 in the GPM shows that Witness Alvarez's claim that GPM inputs are largely based
13 on subjective assessment and is not data-driven are incorrect.

14
15 **Table 3 Analysis of GPM input data**
16

Impact dimension	Objective Inputs	Subject Matter Inputs	Total by dimension	% of total
Reduce Electrical Hazards	x		3,016	11%
Overload Relief	x	x	3,999	15%
Capacity Relief	x	x	3,019	11%
Regulatory Compliance		x	400	1%
Investment in EJ communities	x	x	4,731	18%
Major Event Risk	x	x	2,740	10%
SAIDI	x		2,881	11%
SAIFI	x		2,352	9%
O&M Avoidance	x		2,476	9%
Capital Avoidance	x		1,289	5%
Total Score			26,904	

17

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1 **Q55. In AG-MN Witness Alvarez’s alternative recommendation to the GPM, the**
2 **risk-informed benefit cost methodology used in California for the four**
3 **investment owned utilities RAMP filings, what benefits are monetized?**

4 A55. Projects in these filings are evaluated on 1) Safety – using the Department of
5 Transportation’s value of statistical life (VSL) and 2) Reliability – using the LBNL
6 ICE calculator.²⁰

7
8 **Q56. Does this alternative method avoid non-objective assumptions for safety and**
9 **reliability?**

10 A56. No, both values were developed based on subject matter expert (SME) analysis. As
11 an example, the ICE calculator, which the Company uses in BCAs presented in this
12 case, is based on survey data of both residential and commercial customers and asks
13 questions about willingness to pay to avoid outages. The survey data was then
14 shaped by SMEs to create the ICE calculator formula(s). This is not to say that the
15 Company disagrees with the ICE calculator values, in fact the Company is actively
16 engaged with LBNL on the development of ICE 2.0, rather it demonstrates that the
17 ICE calculator, an industry standard tool for measuring reliability, is an example of
18 using expert judgement to value a non-monetary benefit. In any complex BCA
19 incorporating multiple benefits, it is nearly impossible to avoid using some degree
20 of subject matter expertise to arrive at a benefit cost ratio result.

21

22 **Q57. Does AG-MN Witness Alvarez express concern that the tree trimming**
23 **program is not evaluated in GPM?**

²⁰ See California PUC R20-07-013, Dec 15, 2022, Decision 22-12-027, Phase II Decision Adopting Modifications, pp35-38. <https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=500014668>

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1 A57. Yes, his third concern about the GPM, as he states on page 48, is that the GPM is
2 not used to score the tree trimming program.

3

4 **Q58. Do you agree with this concern?**

5 A58. No. When first developing the GPM, the Company did run the tree trim program
6 through the model. As stated in the Company's first Distribution Investment and
7 Maintenance plan, "Tree trimming to the enhanced specification...continues to
8 provide the highest customer benefits of any program in the five-year investment
9 portfolio"²¹. Tree trimming is an effective program; the Company will continue to
10 complete the surge and maintain the cycle. However, at this point the Tree Trim
11 program is concluding the Surge and transitioning to maintaining our system, tree
12 trimming should be considered a required, fundamental, baseline activity. It is also
13 an O&M expense, therefore including it in the GPM does not aid in prioritizing
14 capital projects.

15

16 **Q59. Does AG-MN Witness Alvarez express concern that projects and programs**
17 **are prioritized together in the GPM?**

18 A59. Yes, a fourth concern, stated on page 47, lines 15-22, is that the GPM does not
19 distinguish between projects and programs, and does not factor into program
20 scoring the potential variability of impacts a program will have on different circuits.

21

22 **Q60. Does the Company share AG-MN Witness Alvarez's concerns about including**
23 **both projects and program in the GPM for prioritization?**

²¹ DTE Electric's Five Year (2018-2022) Investment and Maintenance plan, filed in docket U-18014 on 1/31/2018, p18

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1 A60. The Company acknowledges that it is challenging to compare projects and
2 programs, which is one of the foundational reasons the GPM was developed. Prior
3 to the development of the GPM, the Company did not have an objective
4 standardized method that accounted for both relative benefits and costs and allowed
5 for comparison of programs, large projects, and small projects on a level playing
6 field. For programs specifically, it would be impractical to prioritize investments if
7 each of the thousands of projects for specific distribution circuits were prioritized
8 individually for every applicable program. Instead, program benefits are calculated
9 at the aggregate for a 5-year period and ranked. For many programs, including the
10 programs Witness Alvarez cites (PTMM, Distribution Automation, and 4.8kV
11 Hardening), the benefits are calculated from the Reliability Model based on the
12 specific planned circuits that will receive the program investments. Each individual
13 program uses prioritization criteria relative to its strengths to identify circuits which
14 will receive the highest benefit from the program. Programs may defer or skip
15 altogether circuit where benefits are found to be low within the program
16 prioritization. Both the PTMM BCA spreadsheet and the Distribution Automation
17 prioritization methodologies have been provided as evidence in this case to support
18 how investments are prioritized within programs.

19

20 **Q61. Does AG-MN Witness Alvarez make claims that program and project score**
21 **can be manipulated?**

22 A61. Yes, a fifth concern is summarized on page 46 lines 15-17: “A model user can get
23 the GPM outputs he or she desires for a particular project or program simply by
24 manipulating subjectively-assessed model inputs for the project or program.”

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1 **Q62. How does the Company prevent results in the GPM from being manipulated?**

2 A62. The scores in the GPM cannot be manipulated in the way Witness Alvarez claims
3 for multiple reasons. First, as already discussed, most of the inputs to the model are
4 based on objective measured data such as historical reliability, measured loading,
5 and external inputs such as the MiEJ Screen tool. Second, the methods used to
6 calculate scores based on these objective inputs have been consistent over time and
7 are applied uniformly to the projects and programs that are being evaluated. Third,
8 the Company has requested feedback from stakeholders during technical
9 conferences and DGP filings on suggested changes to weightings and assumptions.
10 Lastly, and most importantly, the entire model has been provided as a workpaper
11 in this case, Exhibit A-43, Schedule HH4 - WP AJK U-21534 GPM in my rebuttal
12 testimony, so all assumptions and weighting can be examined. The Company
13 intends to provide the model in future DGPs and rate cases so that any year over
14 year changes will be transparent.

15

16 **Q63. Do you have any additional comments about AG-MN Witness Alvarez's claim**
17 **that the GPM can be manipulated?**

18 A63. Yes. The Company is under considerable pressure from its customers, regulators,
19 and elected officials to quickly improve reliability. The Company's incentives are
20 firmly aligned with identifying the programs that deliver the most benefits per
21 dollar and has no interest or reason to engage in model manipulation.

22

23 **Q64. Does AG-MN Witness Alvarez's testimony suggest using alternative project**
24 **ranking methodologies that are fundamentally flawed and should not be used?**

Line
No.

1 A64. Yes, the sixth and last concern the Company will address is Witness Alvarez's
2 assertion that the GPM does not include a proper 'baseline'. The testimony goes on
3 to discuss two flawed alternative methodologies.
4
5 The first flawed methodology is assuming that the percent reduction from the
6 baseline should be factored into the GPM scoring. He states on page 46 lines 8-12:
7
8 "Risk reduction estimates (such as a projected reduction in customer minutes
9 interrupted) are input with no indication of the scale of the reduction relative
10 to current state risk. For example, does a 100,000 minute reduction in
11 customer minutes interrupted represent a 2% reduction from the baseline or a
12 50% reduction from the baseline?"
13
14 To start, the GPM does, in most cases, include both the baseline and the
15 improvement, contrary to Witness Alvarez's assertion. An example is shown in
16 Table 4 below, which is in the "Reliability – SAIDI" tab of the GPM, Exhibit A-
17 43, Schedule HH4 - WP AJK U-21534 GPM. As seen in the table, most investments
18 include Customers Minutes Interrupted (CMI) "CMI Before" as the baseline. These
19 values are derived from historical reliability of the circuits being addressed by the
20 specific GPM projects. The baseline for programs, such as PTMM, CEMI, 4.8kV
21 Hardening, and Distribution Automation, is the system wide historical SAIDI
22 performance. More importantly though, the key measurement of risk reduction is
23 "CMI Avoided per \$M invested", which has no correlation to the percentage
24 reduction from the baseline. Given a finite budget, the projects that will provide the
25 most overall benefit from this tab of the GPM are those with the highest CMI per
26 \$M invested, not those with the highest CMI compared to a baseline, as Witness
27 Alvarez suggests. In fact, using Witness Alvarez's example, assuming equal project
28 costs, a 100,000 minute reduction has the same benefit to our system regardless if

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1 it's a 2% reduction or a 50% reduction from the baseline. However, if the 100,000
2 minutes from the 2% project was half the price of the 100,000 minutes from 50%
3 project, the GPM (and the Company) would select investment in the 2% project.

4 **Table 4 'Reliability-SAIDI' tab of GPM**

RowID	Project ID	Project/Program Name	Capital Investment	CMI Before	CMI Savings	CMI Avoidance per \$M Invested	Score
1	2005 ADMS: DMS/OMS		\$ 91,844,058	0	98,611,830	\$ 1,073,688	752
2	1015	40 kV: Automatic Pole Top Switch	\$ 31,800,000	0	16,186,250	\$ 509,002	356
3	2007	Frequent Outage Program (CEMI)	\$ 48,049,745	0	22,926,268	\$ 477,136	334
4	2008	Pole and Pole Top Maintenance and Modernization (PTMM)	\$ 715,450,000	0	297,893,299	\$ 416,372	291
5	2017	Distribution Automation	\$ 1,162,788,221	0	346,230,878	\$ 297,759	208
6	20201053	4.8 kV CC: Hawthorne Relief and Circuit Conversion	\$ 94,029,812	23,056,762	19,598,248	\$ 208,426	146
7	2001	4.8 kV Hardening	\$ 259,000,000	0	27,566,077	\$ 106,433	75
8	2029	4.8 kV CC: ISO Conversion Program	\$ 25,350,000	0	2,520,996	\$ 99,448	70
9	20230004	4.8 kV CC: MAUME 8241 Downtown Clawson Conversion	\$ 2,627,140	285,526	242,697	\$ 92,381	65
10	2004	URD Replacement Program	\$ 72,041,398	0	5,151,733	\$ 71,511	50
11	20191025	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion	\$ 330,838,051	22,846,946	19,419,904	\$ 58,699	41
12	20201054	4.8 kV CC: Belleville Substation and Circuit Conversion	\$ 11,385,184	699,141	594,270	\$ 52,197	37
13	20230006	4.8 kV CC: Zenon Circuit Conversion Phase 2	\$ 155,800,000	7,907,726	6,721,567	\$ 43,142	30
14	20230013	4.8kV CC: Hemlock Decommissioning and Circuit Conversion	\$ 68,039,683	3,352,653	2,849,755	\$ 41,884	29
15	2002	Breaker Replacement Program	\$ 70,799,000	0	2,916,000	\$ 41,187	29
16	20191024	4.8 kV CC: Royal Oak Substation and Circuit Conversion	\$ 547,652,366	24,629,899	20,935,414	\$ 38,228	27
17	20230019	4.8kV CC: Yale-Slater Decommissioning and Circuit Conversio	\$ 43,951,541	1,968,047	1,672,840	\$ 38,061	27
18	20191037	4.8 kV CC: Birmingham Decommissioning and Circuit Convers	\$ 53,720,709	2,387,430	2,029,315	\$ 37,775	26
19	20201064	4.8kV CC: Rochester Decommissioning and Tienken Relief	\$ 27,790,000	1,197,949	1,018,257	\$ 36,641	26
20	20191082	8.3 kV CC: Pontiac Overhead/Underground Conversion	\$ 174,407,073	6,926,375	5,887,419	\$ 33,757	24

5

6 **Q65. What is the second methodology that AG-MN Witness Alvarez proposes?**

7 A65. Witness Alvarez describes "Risk-Informed Decision Support" on pages 49-50
8 along with an example shown on page 50 of how to select the optimal investments.
9 His conclusion is that the optimal solution is retaining (investing in) projects 1, 2
10 and 3, which is mathematically incorrect. The Company conducted its own analysis
11 to optimize the hypothetical portfolio to demonstrate why his methods are incorrect

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1 and lead to the wrong conclusion. When ranked on benefit (Risk Reduction) vs cost
2 (PVRR), the far right column in the table below, the optimal portfolio would select
3 Projects 1, 5, 3 and 2, in that order, and project 5 should certainly be prioritized
4 before projects 2 and 3. See Table 5 below for calculations. If the Company GPM
5 methodology is used, project 5 has the second highest score and it would be
6 apparent that it should be selected over projects 2 and 3 because it clearly provides
7 the most value per dollar invested. Witness Alvarez’s method failed to achieve this
8 result and should be rejected.

9 **Table 5 Optimal analysis of project portfolio**

Project	PVRR (\$M)	Risk Reduction	Risk Reduction per \$M PVRR
1	\$ 24	180	7.6
2	\$ 49	147	3.0
3	\$ 39	125	3.2
4	\$ 88	79	0.9
5	\$ 15	74	4.9
6	\$ 40	68	1.7
7	\$ 34	53	1.6
8	\$ 19	41	2.1

10

11 **Rebuttal Issue 7: Reliability Model**

12 **Q66. AG-MN Witness Alvarez criticizes the Company’s use of the Reliability Model**
13 **when he claims that “DTE uses the Reliability Model’s improvement**
14 **projections to justify the size of its strategic capital program budgets. By**
15 **implication, the Model’s reliability improvement projects are also intended to**
16 **justify most of the Company’s request to extend and expand rider IRM”²²?**
17 **Does the Company agree with his statement?**

²² Alvarez DT p. 53, lines 2-5

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1 A66. No. The Reliability Model is just one component of the support for the six reliability
2 improvement programs/projects that are included (Tree Trimming, Distribution
3 Automation, PTMM, Customer Excellence, 4.8kV Hardening, and 4.8kV
4 Conversion), it is not the sole justification. Primary justification for the six
5 programs and projects is found in testimony presented by Company Witnesses
6 Deol, Hartwick, Elliott-Andahazy, and Steudle (for tree trimming), in Capital
7 Summaries (Exhibit A-23, Schedule M3-M5) with detailed information on project
8 drivers, scope and benefits, and in the GPM. Additionally, the model is not
9 “intended to justify most” of the IRM investments, as areas of investments such as
10 Breakers, URD, and Subtransmission Redesign and Rebuild projects are not
11 included in the Reliability Model. 4.8kV Conversion projects, while included in the
12 model from a reliability benefit perspective, are typically driven by capacity or
13 aging equipment needs, which are not reflected in the model.

14

15 **Q67. What critique does AG-MN Witness Alvarez provide with regard to the**
16 **Reliability Model?**

17 A67. Witness Alvarez provides four pieces of feedback on how this type of reliability
18 modeling should be performed (pages 53-57), including:

19 1) Project and program analysis that was used to populate the reliability
20 improvements within the model should not have been calculated using a
21 ‘differences of differences’ approach. (page 54)

22 2) The model should separate tree trim impacts from the impact of strategic capital
23 programs. (page 53)

24 3) The model should use multiple years of baseline reliability to account for
25 weather variation. (pages 55-56)

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1 4) The model should use accurate units to project reliability improvements. (pages
2 56-57)

3

4 **Q68. Does the Company agree with the feedback from AG-MN Witness Alvarez?**

5 A68. Yes, in fact all four of those components describe how the Reliability Model
6 actually works.

7

8 **Q69. Based on his testimony, how does AG-MN Witness Alvarez assume benefits
9 are being calculated for use in the model?**

10 A69. Witness Alvarez assumes that DTE Electric is using a ‘differences of differences’
11 approach and discusses drawbacks of this approach for modeling on pages 54-55.
12 Using this methodology, the comparison is between a control group and a test
13 group. The measured benefits would be the difference between the before and after
14 performance of the control group (i.e., Difference 1) and the before and after
15 comparison of test group (i.e., Difference 2). His primary complaint is that he
16 believes the test group has had both tree trimming and a capital investment, whereas
17 the control group has neither, and thus the results are combining the impact of both
18 tree trimming and the capital investment.

19

20 **Q70. Does the Company use the ‘differences of differences’ approach for modeling
21 reliability benefits in the reliability model?**

22 A70. No. The reliability model uses a different type of analysis that was provided in
23 discovery and included in Exhibit A-43, Schedule HH6 - MNSCDE-12.8b -
24 Reliability Program Analysis.

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1 **Q71. How are the projected reliability benefits calculated for use in the Reliability**
2 **Model?**

3 A71. Table 6 for 4.8kV Hardening is shown below as an example. The “before”
4 performance is the event volume the year 4.8kV hardening work is completed on a
5 group of circuits and has a 0% reduction in events as the baseline. The “after” period
6 consists of the years after the work has been performed and will have a negative
7 number indicating a reduction in event volume from the baseline. For example,
8 work that was completed a few years ago, such as 2018, has four ‘after’ years,
9 whereas work completed in 2021 currently only contains analysis on a single after
10 year. Because the comparison is a “before” and “after” on the same set of circuits,
11 there is no control group as Witness Alvarez assumes in his testimony, and all the
12 circuits have undergone tree trimming as a pre-cursor to 4.8kV Hardening work. If
13 anything, some benefits may accrue to the circuits in the “before” year since it is
14 the year work is being done, which could have the result of lowering the starting
15 point for events tracking, and thereby understating the benefits of the program. The
16 table is meant to be read left to right with the third column, listing the years 2017-
17 2021, representing the years a group of circuits were completed. Take 2020 (second
18 row from the bottom) as an example, 30 circuits were completed that year and the
19 first year post hardening (2021 – second column from the right) the analysis shows
20 75% improvement for this group of circuits.

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1

Table 6 4.8kV Hardening Event Reduction

4.8kV Hardening								
			% change in events					
	# of Circuits		2017	2018	2019	2020	2021	2022
0%	0	2017	0%	0%	0%	0%	0%	
7%	5	2018		0%	-76%	-90%	-86%	-71%
25%	18	2019			0%	-79%	-78%	-76%
42%	30	2020				0%	-75%	-78%
26%	19	2021					0%	-84%

2 **Q72. Does AG-MN Witness Alvarez believe that the Reliability Model mixes the**
3 **impact of tree trim events and non-tree trim events?**

4 A72. Yes. On page 53, lines 15-17 he states “DTE did not attempt to isolate the impact
5 of tree trimming from the impact of strategic capital program spending when
6 determining historical reliability performance of the programs.”

7

8 **Q73. Did DTE Electric isolate the impact of tree trimming from strategic capital**
9 **improvements in the Reliability Model and supporting analysis?**

10 A73. Yes, this isolation is incorporated in two ways. First, as also was provided in
11 MNSCDE-12.8b, Exhibit A-43, Schedule HH6 - MNSCDE-12.8b - Reliability
12 Program Analysis, the benefits are calculated separately for tree-related and non-
13 tree related events. The Tree Trimming benefits analysis only looks at tree-related
14 event reduction, whereas the capital programs such as 4.8kV Hardening only look
15 at non-tree related event reduction. Secondly, the circuit-level baseline is calculated
16 and projected separately for tree and non-tree related outages. This was stated in
17 my revised direct testimony in Q85 (bold added for emphasis): “Each circuit has a
18 baseline of reliability performance based on five years of historical, non-MED
19 event volume. **Events are further divided into tree and non-tree**, single and

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1 multiple, and outage and non-outage”. In other words, the model completely
2 isolates tree and non-tree related events to project reliability impacts.

3

4 **Q74. Does the model use multiple years of data to account for weather variability?**

5 A74. Yes, as also shown in Table 6 above, the reliability benefit assumptions use multiple
6 years of weather data in the baseline by using circuits which have had treatment
7 across multiple years. The baseline, in this example, includes weather from 2018-
8 2021. Additionally, the model uses non-MED event volume as the basis for
9 calculations, which is likely less volatile to weather impacts than either all-weather
10 events or non-MED reliability metrics such as customer minutes interrupted.

11

12 **Q75. AG-MN Witness Alvarez states on page 58, lines 2-5 that “As costs typically**
13 **go up over time, not down, particularly in these inflationary times, I am**
14 **concerned that the number of “units completed” in the model are exaggerated**
15 **relative to the number of units the Company will be able to complete for the**
16 **capital budgets indicated.” Does the Reliability Model use accurate counts of**
17 **units aligned to the Company’s investment plan?**

18 A75. Yes, the model uses the same units and circuits for projecting reliability input as
19 were provided in this instant case testimony, such as Table 12 in Witness Elliott
20 Andahazy’s revised direct testimony, and multiple discovery responses like Exhibit
21 A-53 Schedule RR1. PTMM, 4.8kV Hardening, Distribution Automation, and
22 4.8kV Conversion, and Tree trimming circuits selected in the model for 2024 and
23 2025 are aligned with the execution plan for those programs and projects.

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1 **Q76. Does AG-MN Witness Alvarez provide an analysis on the unit costs that he**
2 **uses to support a claim that the units in the model are overstated?**

3 A76. Yes, Witness Alvarez presents a table, on pages 56-57 of his direct testimony, with
4 unit cost comparisons in 2024 and the last year data is available and claims
5 significant reductions in unit costs imply that the units used in the Reliability Model
6 cannot be achieved.

7
8 **Q77. Does the unit cost analysis AG-MN Witness Alvarez provides have flaw or**
9 **errors in it?**

10 A77. Yes, there are three different factors impacting the calculations in this table that
11 prevent us from drawing any conclusions from the analysis. First, when dividing
12 total investments by units to get cost per unit, the costs Witness Alvarez used are
13 off by a factor of ten, and therefore the whole table is off by an order of magnitude.
14 For example, the average costs to convert a mile of 4.8kV in 2024 is approximately
15 \$2.5 million using the units in the Reliability Model and the investments in A-12
16 Schedule B5.4, not \$256,000 as listed in the table. Secondly, Witness Alvarez does
17 not include all costs in his calculations for future years. For 4.8kV Conversions, he
18 stated in footnote 54, on page 56 that he used Exhibit A-33 Sch X1 (IRM), which
19 shows \$199 million in conversion investments in the proposed 2027 IRM. Not all
20 cost recovery for 4.8kV Conversions will occur through the IRM, so the costs he
21 used are only a subset of the total. The most complete description of the Company's
22 plans to convert the 4.8kV system, particularly for years beyond the test year of this
23 case, is the 2023 DGP. On page 117 of the DGP (Exhibit A-23, Schedule M8), the
24 projected 4.8kV capital investment in 2027 is \$372 million (significantly different
25 than the \$199 million used in the table calculations). Projections in the Reliability

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1 Model are based on the total investments in the distribution system and are agnostic
2 to the cost recovery mechanism (IRM vs rate case). Similar to his conversion costs
3 assumptions, Witness Alvarez uses partial or inaccurate cost information to
4 calculate Automation costs per unit, because funding for that program exists in both
5 the IRM and the rate case. Finally, his analysis fails to account for other
6 programmatic factors. For example, the 2026 investments in 4.8kV Hardening
7 consist almost entirely of construction of line miles. Other costs such as design and
8 tree trim generally occur the year prior. There are no costs in 2026 associated with
9 trimming or designing circuits for construction in 2027, as the program will be
10 complete. Therefore, a significantly lower and inaccurate for comparison cost per
11 unit would be expected. 4.8kV Conversion projects may also experience a lower
12 cost per unit in the future as the work mix will shift from CODI projects, which
13 include significant underground scope and less overhead miles, to projects outside
14 of CODI which typically involve more overhead rebuild. Given these three factors,
15 the analysis of the table cannot be used to draw any valid conclusion, much less
16 conclude that cost per unit in the reliability Model are exaggerated.

17

18 **Q78. Does the Company agree with AG-MN Witness Alvarez's position that that**
19 **model results are inaccurate if profits are not tied to model accuracy²³?**

20 A78. No, the Company does not agree. Placing profits at risk is completely unrelated to
21 the logical assumptions and math of the model, and this type of criticism offers no
22 constructive feedback or path forward on how to improve model accuracy.
23 Additionally, the Company cited weather variability as one rationale to not directly
24 tie potential future system performance to model output. While Witness Alvarez

²³ Alvarez DT, page 57, line 13-14

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1 states “there are ways to address this concern.” (page 57, line 14-15), he remains
2 silent on what any of those ways are.

3

4 **Q79. Does the Company plan to continue to evaluate and improve the Reliability**
5 **Model over time?**

6 A79. Yes, the Company will continue to measure reliability benefits of the modelled
7 programs and update expected benefits as additional data and analysis is available.
8 The Company may also add additional investment categories to the model, update
9 the degradation analysis, or add a factor in to account for more severe weather.
10 Lastly, if the data and modeling indicate that a program is not performing as
11 expected, the Company will also reevaluate that program for future investment.

12

13 **Rebuttal Issue 8: Investment Changes between the 2023 Distribution Grid Plan and**
14 **the Instant Rate Case**

15

16 **Q80. How do you respond to Staff Witness Becker recommendation (page 12, lines**
17 **18-21) to “...improve upon aligning spending plans between DGP and rate**
18 **case filings and instrut the Company to communicate its decisions to increase**
19 **or decrease spending in categories after DGP is filed.”?**

20 A80. The Company, in general, supports Witness Becker’s recommendation to improve
21 the alignment of investment plans between DGP and rate case filings. The
22 Company’s goal is to improve transparency into distribution system investment
23 plans and related investment projections for its regulators, customers, and other
24 stakeholders. However, there is a basis for the discrepancy in investment levels. A

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1 summary of explanations for the most significant changes in investments levels
2 between the 2023 DGP and the instant case are:

3 1. The \$107 million variance in **Emergent Replacement** for 2025 was largely
4 driven by the years used in the five-year inflation calculation. The 2023 DGP
5 calculated inflation based on 2017 – 2021, whereas the instant case was updated
6 to use calculated inflation based on 2018-2022. The Company will address this
7 misalignment in future DGP filings, however as the DGP and rate case timing
8 are typically not exactly aligned or on the same cadence, the most current filing,
9 either DGP or rate case, will likely continue to use a baseline using the most
10 recent available five-year timeframe.

11 2. The \$100 million variance in **Tree Trimming** is primarily due to a strategic
12 update that occurred post DGP filing that added an additional regulatory asset
13 request of \$87 million in the instant case, aimed at completing the surge by the
14 end of 2025.

15 3. The variance of \$71 million in **Infrastructure Resilience & Hardening** is
16 mainly due to the accelerated enhancement of the 4.8kV Hardening program,
17 targeting completion by the end of 2026. Additionally, the Company initially
18 forecasted a decrease in CEMI investments; however, given the recent
19 reliability performance of the DTE Electric system, the Company determined
20 that this program should continue at its existing funding level until reliability
21 sufficiently improves.

22

23 In the future the Company will work towards minimizing changes to planned
24 investments between the rate case and DPG filings, and when strategic changes are

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1 necessary post DGP filing, the Company will work with Staff to communicate these
2 changes with increased transparency.

3

4 **Q81. Staff Witness Becker proposed a “distribution plan annual update approach**
5 **in its comments to the Company’s 2023 DGP that could serve as a platform to**
6 **communicate changes in projected spend” (Page 12, lines 9-11). How do you**
7 **respond to this proposal?**

8 A81. The Company is willing to collaborate with Staff and develop a process, structure,
9 and requirements of proposed annual updates on changes to near-term investment
10 plans described in the DGP.

11

12 **Rebuttal Issue 9: Electric Vehicles (EVs) and Clean Energy Future Legislation**

13

14 **Q82. Do you agree with AG-MN Witness Alvarez that “...preparing the grid for**
15 **electrification, for example through conversions of 4.8 kV circuits to 13.2 kV**
16 **circuits, does not appear to be an urgent need.”²⁴?**

17 A82. No. The primary purpose for the conversions of 4.8 kV circuits to 13.2 kV circuits
18 in this rate case is to address *current* loading issues, as well as improve safety and
19 reliability. Refer to Company Witness Deol’s rebuttal testimony, pages 7 through
20 11, for further details on the reasons for conversions.

21 An additional benefit to conversion is that it prepares the grid for electric vehicles
22 (EVs) and distributed energy resources (DERs). In Commission Order U-21400,
23 page 12, it states the following:

24 “Beyond this primary focus on distribution reliability and
25 safety, the workgroup shall also consider challenges around

²⁴ Alvarez DT, page 20, line 13-15

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1 the readiness of utility distribution grids to effectively
2 accommodate and leverage the increasing and further
3 anticipated growth of distributed generation, EVs, and other
4 DERs.”

5 The outlook for EVs and DER adoption is anticipated to grow, and the Company
6 recognizes the need for the grid to be well-prepared ahead of the growth, and in
7 support of the growth. The Michigan Healthy Climate plan has a goal to “build the
8 infrastructure necessary to support two million electric vehicles on Michigan roads
9 by 2030”²⁵, approximately 40 times more than the amount of EVs currently
10 registered in Michigan²⁶. Preparing for that level of electrification will require
11 investment in the grid. See Company Witness Bennet’s rebuttal testimony for
12 further information on the Company’s Electric Vehicle forecast, pages 7-13.

13

14 **Q83. Do you agree with AG-MN Witness Alvarez that “...rooftop solar does not**
15 **typically require much distribution grid investment. Only utility-scale, rurally**
16 **located solar systems typically require significant distribution grid**
17 **investments...”²⁷?**

18 A83. No. Witness Alvarez cites his own experience and AG-MN Witness Stephens
19 experience as justification for the statement but does not supply any data or studies
20 for this claim. The Company has already invested and will continue to invest in grid
21 updates that are supportive of the integration of renewables including residential
22 and commercial solar installations. In addition to customer-funded updates that
23 may be required as part of the interconnection process, the Company has evaluated
24 and modified protection and automation schemes, incorporated bidirectional power

²⁵ Mi Healthy Climate Plan, available at <https://www.michigan.gov/egle/about/organization/climate-and-energy/mi-healthy-climate-plan>, accessed August 14, 2024

²⁶ Alternative Fuels Data Center: Maps and Data, available at <https://afdc.energy.gov/data/10962>, accessed August 14, 2024 <https://afdc.energy.gov/data/10962>

²⁷ Alvarez DT, p.21, lines 1-3

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1 flow in load analysis and the evaluation of technology solutions to accommodate
2 the bidirectional flow, and invested in interconnection software, hardware,
3 communications, and control systems, to name just a few examples.

4

5 **Rebuttal Issue 10: CEO Witness Volkmann Table of Recommendations**

6

7 **Q84. Did CEO Witness Volkmann make recommendations regarding specific**
8 **recommendations to the Commission?**

9 A84. Yes, on page 28 of Witness Volkmann’s testimony, he makes three
10 recommendations, which are summarized in the table below, along with DTE
11 Electric’s response to his proposals.

12

13 **Table 7 Response to Witness Volkmann Recommendations**

Lines	Recommendation	DTE Electric Response
11-13	1) Provide enhanced reporting of circuit-level reliability program results (for) compared to the Company’s reliability improvement projections.	The Company will continue to measure program effectiveness to refine and validate the Reliability Model which is used to perform reliability projections. The Company notes that it already does provide circuit level reliability performance, starting in 2023, as part of the MPSC reporting requirements and shown on the MPSC website ²⁸ , and that the Reliability Model projects individual circuit reliability. The Company is also open to continuing to work with CEO and other stakeholders if the Reliability Model methodology does not provide the information they are seeking.

²⁸ Distribution System Reliability Metrics, available at <https://www.michigan.gov/mpsc/consumer/electricity/distribution-system-reliability-metrics>, accessed August 15, 2024

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Lines	Recommendation	DTE Electric Response
14-16	2) Work with Staff and interested stakeholders to design a VPP pilot/demonstration project for resilience and peak load reduction use-cases using a third-party aggregator, and to include the pilot/demonstration in its 2025 DGP.	Witness Farrell discusses current demand response offerings and progress on third party aggregation engagement.
17-19	3) Work with Staff and interested stakeholders to define its approach for scaling up piloted technologies and incorporating [Non -Wires Alternative] NWA solutions into its distribution planning process. DTE Electric should explain the approach in its next DGP.	The Company screens load-related strategic investments for NWA opportunities and typically finds the load constraints that are being addressed are generally not suitable for NWA projects. The Company is committed to completing the pilots underway and communicating lessons learned in order to inform discussions on how to scale the piloted technologies.

1

2 **Q85. Did CEO Witness Volkmann make other requests specifically to DTE Electric**
3 **in his direct testimony?**

4 A85. Yes. Many of his requests are covered elsewhere in my rebuttal testimony or in the
5 testimony of other DTE Electric Witnesses. For brevity I've included DTE
6 Electric's response to his requests in the table below.

7

8

Table 8 Response to Witness Volkmann Requests

Page:Lines	Recommendation	DTE Electric Response
28:21-23	1) Provide additional information about EJ Community impacts in its next DGP, including how customers are benefitting from investments and confirming that these benefits are the ones the communities prioritize.	The Company commits to continuing to work with CEO to better understand the analysis being requested.

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Page:Lines	Recommendation	DTE Electric Response
29:1-2	2) Conduct one or more Technical Conferences to further explain its GPM to Staff and stakeholders and explain how it differs from a BCA.	The Company held a Technical Conference before the 2023 DGP was filed and is willing to hold additional conferences if the Commission, Staff, or Stakeholders find it valuable.
29:3-4	3) Conduct one or more Technical Conferences to help Staff and stakeholders understand the DA Prioritization Model's assumptions and calculations.	The Company is willing to hold technical conferences to explain the methodology used to prioritize if the Commission, Staff, or Stakeholders find it valuable.
29:5-7	4) Expand its Reliability Model to include the impacts from URD Replacement, Cable Replacement, Breaker Replacement, and Substation Risk projects and include the enhanced model in its next DGP.	The Reliability Model is based on groups of high volume of outage events, and reliability is projected at the circuit level. URD, Cable, and Breaker events are significantly lower volume and are not a good fit to be included in the model. It would add significant complexity without providing much additional clarity. Estimates for reliability impact for these are better done at a system-wide level. The Company is willing to meet and discuss the technical details with those stakeholders who are interested.
29:8-9	5) Collect and incorporate actual outage data to refine the assumptions in its Reliability Model.	This is referenced earlier in my rebuttal under the Reliability Model section. The Company will refine model assumptions as actual outage data is collected and analysis is performed.
29:10-12	6) Refresh its assumptions in the DA Prioritization Model with the actual customer interruption and outage duration impacts from automation as the data become available.	The Company will refresh the model assumptions with new data and learnings as long as the model remains in use.

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Page:Lines	Recommendation	DTE Electric Response
29:13-16	7) Expand the Company's application of its BCA methodology to its 4.8kV Conversion, Distribution Automation, Frequent Outage, Subtransmission Redesign & Rebuild, Breaker Replacement, URD Replacement, Cable Replacement, and Tree Trimming Surge programs.	Future BCA plans were discussed in my Cost Benefit Analysis section. The Company is exploring options to conduct BCAs on additional projects or programs.
29:17-18	8) Make necessary modifications to its outage management systems to begin incorporating actual DTE Electric failure data in its BCA methodology	The Company plans to continue to improve data collection through its OMS to provide a richer data source for BCAs and other analysis.
29:19-20	9) Consider partnering with LBNL to quantify the resilience impacts of DTE Electric's planned investments using POET, for inclusion in future BCAs.	See item 7) above. The value of resiliency is a benefit that could be considered in future BCA analysis, whether through POET, which the Company will explore in preparation for the next DGP, or other methodologies.
29:21-22	10) Modify its BCA methodology to reflect the full revenue requirements of investments.	The Company will consider this modification in future BCA efforts.

1

2 **Rebuttal Issue 11: Environmental Justice (EJ)**

3

4 **Q86. What recommendations have been made by Witnesses regarding the**
5 **Company's Environmental Justice (EJ) analysis?**

6 A86. Several Witnesses requested that the Company do more tracking and reporting of
7 EJ-related metrics, as well as more granular, detailed EJ analysis Specifically:

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- 1 • DAAO Witness Koeppel states "The Commission should require DTE to
2 analyze changes in demographics over time when assessing the equity
3 impacts of its proposed long-term investments."²⁹
- 4 • CEO Witness Kenworthy states "DTE should also consider how equity is
5 integrated into its operational practices."³⁰

6

7 **Q87. How does the Company respond to the Witnesses' requests?**

8 A87. The Company does not believe that a Commission order requiring additional EJ
9 analysis is needed at this time. Please refer to my revised direct testimony in Part
10 XI which describes how EJ is currently considered when proposing long-term
11 investments. The Company recognizes that EJ issues, data, tools, and analysis will
12 continue to evolve. For example, the State just launched MIEJScreen Version 1.0³¹.
13 The Company will continue to analyze the most current data and tools available
14 and looks forward to continuing to collaborate with stakeholders to gather their
15 input on the future analysis and development of plans for the 2025 DGP.

16

17 **Q88. DAAO Witness Koeppel states that "While the MIEJ Screen tool is a useful
18 starting point for identifying areas with high concentrations of low-income and
19 vulnerable populations, it does not provide a sufficiently granular or
20 differentiated picture of the specific needs, challenges, and opportunities
21 facing individual neighborhoods, households, or customer subgroups within**

²⁹ Koeppel DT, page 47, lines 6-8

³⁰ Kenworthy DT, page 21, line 15

³¹ State launches MiEJScreen Version 1.0 to illuminate environmental, health and socioeconomic conditions in communities, available at <https://www.michigan.gov/egle/newsroom/mi-environment/2024/08/06/state-launches-miejscreen-version-1>, accessed August 15, 2024

Line
No.

1 **each tract.” (Pages 41, line 21-22 through page 42, lines 1-3). How do you**
2 **respond?**

3 A88. The Company is continuing to use the Draft MiEJScreen tool to identify vulnerable
4 customer areas. The Company believes this is the appropriate tool to use for
5 distribution analysis, because it was developed with extensive input from Michigan
6 stakeholders, including experts in the EJ community, is maintained by the State of
7 Michigan, and includes a breadth of socioeconomic and environmental factors in
8 its EJ impact scoring (Witness Kryscynski revised direct testimony, page 80, Figure
9 11). In addition, the census tract data is granular enough for DTE Electric to use in
10 reliability planning. More granular breakdowns of individual streets of
11 neighborhoods are not particularly useful because grid solutions typically need to
12 be addressed at the circuit or substation level.

13

14 **Q89. How do you respond to DAAO Witness Koepfel’s statement that “In DTE’s**
15 **current mode of equity analysis, these differences continue to be flattened by**
16 **a binary assessment of vulnerable vs. not vulnerable tracts.”³²?**

17 A89. While the Company does use the descriptors of “vulnerable” to describe customer
18 geographic areas with 80-100 MiEJscreen scores, and “non-vulnerable” to discuss
19 those with scores less than 80, the Company does in fact calculate and consider
20 smaller gradations. As an example, in response to the Commission’s direction in
21 Case No. U-21297 to conduct in depth EJ analysis, the Company (in the instant
22 case) sharpened the analysis into 5% gradients.

23

³² Koepfel DT, page 42, lines 16-17

Line
No.

1 **Q90. Do you agree with DAAO Witness Koepfel’s statement that “...the CODI**
2 **areas nonetheless likely count towards Kryscynski’s binary bucketing of**
3 **“vulnerable” census tracts” (page 43, lines 7-9) to be accurate?**

4 A90. No, his statement is inaccurate and not supported by the analysis the Company
5 provided in this case. CODI projects are evaluated individually in the GPM, and EJ
6 scores are applied only if the project directly impacts the census track. The EJ score
7 averages the collective census tract scores, weighted by customers impacted in each
8 tract.

9

10 **Q91. DAAO Witness Koepfel criticizes specific CODI investments supported by**
11 **Company Witness Deol as not improving service to vulnerable populations,**
12 **and further criticizes Witness Kryscynski based on a presumption that these**
13 **projects then “count” in what he perceives are binary bucketing of vulnerable**
14 **census tracts. (Koepfel, page 42, lines 16-17, and page 43, lines 6-10). How does**
15 **the Company respond?**

16 A91. In addition to my comments immediately above about the granularity of MiEJ
17 screening tool scoring and the evaluation of CODI projects, DAAO Koepfel seems
18 to misunderstand the Company’s use of EJ as one factor in addition to other factors
19 in evaluating projects and programs through GPM. The multiple factors including
20 reliability, safety, and EJ results in a balanced portfolio of investments that support
21 multiple grid objectives for all customers, including those who are the most
22 vulnerable. The diverse set of projects and programs go beyond the criticized
23 CODI conversions and include as examples like the 4.8kV Hardening program in
24 Detroit, to the replacement of at-risk equipment at Chestnut substation in Madison
25 Heights, to circuit conversions to support safety, reliability, and capacity in Pontiac.

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1

2

In addition, Witness Koepfel undercuts his own claim that CODI is not sufficiently

3

EJ focused with a map in his testimony (Figure 1 on page 44), that shows that the

4

vast majority of the area in the CODI has a an MIEJScreen Tool score of over 80

5

with well over half the area with a score over 90. I have included his figure in my

6

testimony for easy reference as Figure 3.

7

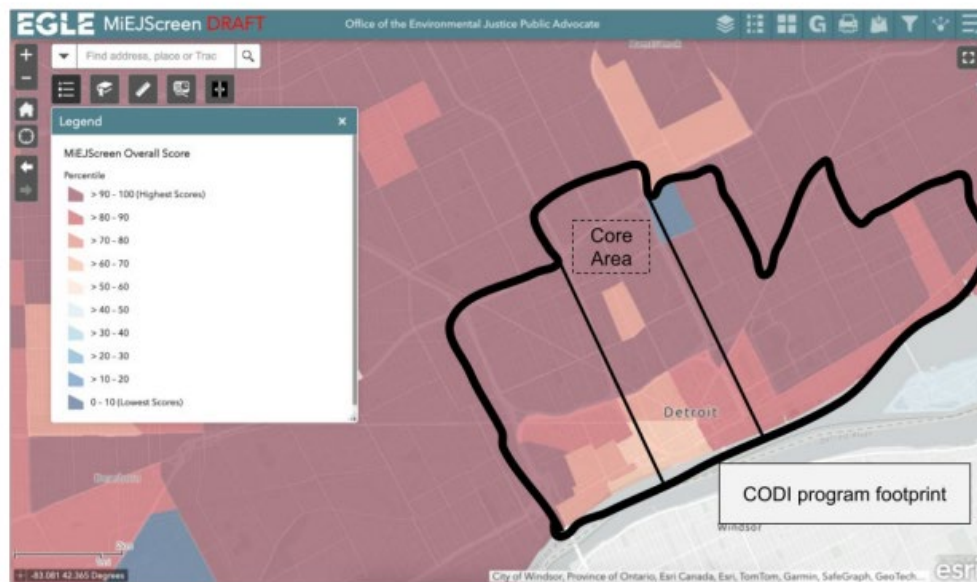
8

Figure 3 MIEJScores of Downtown Detroit and Surrounding Areas

9

from Witness Koepfel's Testimony (page44)

Figure 1: MiEJScreen Grab, Economic Development and Load Growth Map⁵⁷



10

11 **Q92. DAAO Witness Koepfel states that table 14 on page 92 of your direct**

12

testimony “indicates a strong potential that population density is a significant

13

factor in reliability performance.”³³ Do you agree?

³³ Koepfel DT, p. 44, lines 8-9

Line
No.

1 A92. No. There is no way to accurately draw this conclusion from the information
 2 provided in Table 14. The table shows the distribution of residential customers in
 3 each EJ gradation but does not provide enough information to make a determination
 4 of relative population density. This is because the table, included here as Table 9
 5 for easy reference, does not indicate the number of census tracts within each
 6 grouping, and more importantly, does not include the square miles associated with
 7 each grouping. Furthermore, density has additional complexity such as, within a
 8 given area, whether the population is spread apart equally or clustered in one
 9 location.

10

11

Table 9 Residential Customers by EJ Gradations

Census Tract EJ % Group	Number of Residential Customers	% of Residential Customers
0-5%	7,569	<1%
5-10%	39,705	2%
10-15%	62,143	3%
15-20%	43,497	2%
20-25%	59,888	3%
25-30%	88,033	4%
30-35%	100,487	5%
35-40%	99,318	5%
40-45%	102,680	5%
45-50%	114,416	6%
50-55%	120,730	6%
55-60%	135,206	7%
60-65%	124,240	6%
65-70%	126,463	6%
70-75%	100,278	5%
75-80%	146,161	7%
80-85%	127,270	6%
85-90%	162,145	8%
90-95%	143,144	7%
95-100%	114,874	6%
Unmapped/Unscored*	38,383	2%
Total Residential Customers	2,056,630	100%

12

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1 **Q93. GLREA Witness Rafson claimed that “According to the Center for Disease**
2 **Control [CDC], a 1% drop in socioeconomic status results in waiting 170**
3 **minutes longer on average to restore power.” (Page 5, Lines 8-9), with a**
4 **reference to an article in an online publication called “Governing”, by authors**
5 **Chuanyi Ji, Georgia Institute of Technology, and Scott C. Ganz, Georgetown**
6 **University. Do you have any concerns about his claim and conclusions with**
7 **respect to the applicability to DTE Electric’s vulnerable customers?**

8 A93. Yes. First, I’d like to clarify that the conclusion of the relationship between
9 socioeconomic status and power restoration time was the work of authors Ji and
10 Ganz, not the CDC. The CDC socioeconomic status data was simply used to
11 represent the populations as one factor in their analysis. The CDC has a database
12 similar to Michigan’s MiEJ Screening tool. Secondly, the article was in reference
13 to data for 15 million consumers in 588 U.S. counties between 2017-2020. DTE
14 Electric has chosen to use more recent data in its EJ analysis, using the MiEJ
15 screening tool to include multiple factors to define vulnerability, and most
16 importantly, data for the Company’s specific customers, not the broader US
17 population. Finally, the Company would note that the article referenced by Witness
18 Rafson went on to provide hypotheses for the longer restoration times, including
19 that the communities they referenced may be in predominantly older neighborhoods
20 where power infrastructure may require more significant repairs. This is consistent
21 with the testimony of Company Witnesses Deol and Elliott Andahazy when they
22 describe the need for Conversion and Hardening to support improved reliability for
23 the Company’s oldest 4.8kV infrastructure.

24

Line
No.

1 **Q94. DAAO Witness Jacob expresses concern about DTE Electric’s reliability**
2 **performance and investments related to EJ by stating that “DTE Energy has**
3 **not invested in grid and line updates equitably within low-income communities**
4 **and communities of color in metro Detroit.” (Page 3, Lines 22-23). Does the**
5 **Company agree with this characterization of past investment practices?**

6 A94. No. Witness Jacob provides absolutely no support in testimony to substantiate these
7 claims of inequitable investment. The Company, however, has provided evidence
8 to support that it has been investing heavily in EJ areas.

9

10 **Q95. How does the Company describe its grid investment from an EJ perspective?**

11 A95. The Company is maturing in its approach, including consideration of EJ as a factor
12 in prioritization of grid improvements. As described in my revised direct testimony,
13 the Company evaluated how its investment programs are reaching vulnerable
14 communities to improve reliability performance. For example, of the nearly half
15 billion dollars of investment in the 4.8kV Hardening program since 2018, 85% of
16 work performed under the Hardening program occurred in vulnerable communities.
17 Further details are included in my revised direct testimony (pages 93-101) and the
18 section 12.2 of the 2023 DGP (Exhibit A-23 Schedule M8).

19

20 **Q96. CEO Witness Tan provided an updated regression analysis with 2023**
21 **reliability data³⁴, are there concerns regarding the errors within the analysis?**

22 A96. Yes. The Company had one of its in-house data scientists, Dr. Joseph Naiman,
23 review Witness Tan’s testimony and attachments. Dr. Naiman holds a PhD in
24 Biostatistics from the University of Michigan, Ann Arbor. Dr. Naiman has

³⁴ Tan DT describes the updated analysis on pages 7-8

Line
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1 previously reviewed a similar analysis in the previous DTE Electric rate case U-
2 21297.

3

4 Dr. Naiman identified that Witness Tan’s regression analysis results in the previous
5 case seen in his testimony page 11, table 1 (DTE 2021-2022 AW SAIDI Regression
6 Analysis, from Case No. U-21297) are based on a census tract level data by year.

7 The updated analysis in the instant case, which Witness Tan states is a
8 “improvement”³⁵ of the previous analysis, is based on city level within census tract

9 data for the year 2023 – see results in Witness Tan’s testimony page 12, Table 2
10 (DTE 2023 AW SAIDI Regression Analysis). The reason for this change is that

11 Witness Tan, as identified by Dr. Naiman in his review, mistakenly used a data set
12 based on municipal census tracts. Because census tracts can contain several
13 municipalities, many census tracts were included multiple times in the data set³⁶.

14 Essentially, the updated regression analysis is fundamentally different than the
15 previous analysis.

16

17 **Q97. Are there concerns regarding CEO Witness Tan’s conclusions between the**
18 **updated regression analysis and the previous regression analysis?**

19 A97. Yes. With the updated regression analysis based on city level within census tract
20 information versus census tract information, the Company has concerns about the
21 validity of the comparison between the previous rate case and the instant case
22 regression analyses. Witness Tan assumes that within a census tract the reliability
23 metric is as different as if it was in a completely different census tract miles away
24 (this is a violation of the independence assumption of the type of regression Witness

³⁵ Tan DT, p. 7, lines 20-21

³⁶ Note that the number of data points in Table 1 is lower (~2,900) than the data points in Table 2 (~4,400)

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1 Tan produced). Dr. Naiman ran the regression analysis accounting for the
2 relationship within the census tract and some of the results were no longer
3 statistically different. Furthermore, had Witness Tan run the regression using the
4 same approach as he had for the 2022 data, the level of statistical significance
5 decreases in some variables.

6

7 **Q98. What is the Company’s proposed next step regarding EJ regression analysis?**

8 A98. Separately, the Company is actively working on EJ regression analysis with
9 Witness Tan and Staff that will be included in the 2025 DGP. The Company is
10 looking forward to continuing collaborating with stakeholders on this effort to
11 create a robust regression that all stakeholders, including the Company, can
12 support.

13

14 **Rebuttal Issue 12: Community Coordination**

15

16 **Q99. What did the Commission order in Case No. U-21297 with regard to**
17 **Community Coordination?**

18 A99. The Commission stated that “DTE Electric should coordinate construction
19 activities with local units of government”³⁷. In response, the Commission ordered:

20

21 “Therefore, in its next rate case, DTE Electric shall include a demonstration of its
22 efforts to improve communication and coordination with local governments
23 regarding construction activities.”

24

³⁷ MPSC U-21297 order dated December 1, 2023, page 375

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1 **Q100. How has DTE Electric complied with this requirement?**

2 A100. In revised direct testimony, Witness Kryscynski noted on page 102, lines 6 through
3 22, that the Company frequently, through a variety of methods, communicates and
4 coordinates with municipalities to discuss the details of projects located within
5 communities, benefits, and collaboration opportunities. The Company focuses on
6 removing potential construction conflicts, prior to permits being sought, and
7 provides periodic updates and meetings as requested by individual municipalities.

8

9 Additionally, the Company is focused on improving communication and
10 coordination with municipalities and county road commissions including
11 identifying preferred methods of receive planning and construction updates.

12

13 **Q101. In this rate case, what concerns were expressed in testimony regarding the**
14 **coordination of DTE Electric distribution construction work with other**
15 **utilities and municipalities?**

16 A101. In testimony, MAUI Witness Bunch says that he believes the Company failed to
17 meet the Commission's coordination directive. He states that the Company did not
18 provide "data, a more detailed description of policies and practices, and examples"
19 to show its coordination improvements, page 78, line 17.

20

21 Also, Ann Arbor Witness Stults states "the purpose of the Commission's directive
22 was for DTE to include local governments in the planning and coordination of
23 projects in their early stages in an effort to identify cost savings and efficiencies,
24 not merely to communicate DTE Electric's pre-planned projects to communities",
25 page 23 lines 9-12.

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1

2 **Q102. Can you provide examples of the types of community coordination and**
3 **outreach that the Company already performs, and as was requested by MAUI**
4 **Witness Bunch?**

5 A102. Yes. The Company routinely engages with municipalities, municipal organizations,
6 and others through a variety of methods depending on municipal needs and
7 preferences. Examples include:

- 8 • Permits and Easements Coordination – the Company works with over 400³⁸
9 municipalities in its electric service area for permits and easements,
10 primarily for its strategic investment activities.
- 11 • Regional Affairs Managers – the Company provides each community a
12 regional affairs manager that serves as the point person between the
13 Company and the community. The Regional Affairs managers are typically
14 well known by community officials and are usually the first point of contact
15 for a broad variety of topics, including project coordination.
- 16 • Monthly Community Lighting Meetings – held in areas that the Company
17 provides lighting services
- 18 • Reliability and Resiliency Updates – Periodic updates tailored to individual
19 community needs
- 20 • Project Coordination Meetings - with both DTE Electric and DTE Gas
- 21 • Presentations to City Council, Historic Commission and Neighborhood
22 Associations – conducted as needed
- 23 • Community and Project Open Houses – conducted both proactively and as
24 requested

³⁸ Utility Provider Search, available at <https://utilitysearch.apps.lara.state.mi.us/search>, accessed August 6, 2024

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- 1 • General Community Outreach – conducted through local churches and
- 2 school district
- 3 • Direct Customer Communication – through Blog newsletter, Nextdoor,
- 4 letters, door hangers, emails, etc.
- 5

6 **Q103. Has the Company continued its efforts to improve community coordination**
7 **since after the Commission Order in U-21297 and after the filing the instant**
8 **case?**

9 A103. Yes. Prior to this summer, the Company made electric and tree trimming maps,
10 available to communities (as well as the public), titled “DTE Electric Reliability
11 Improvements Map”. The old map can be accessed at through this link:

12

13 [https://dte.maps.arcgis.com/apps/webappviewer/index.html](https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=5d9dc2eb124445618959ce788086e00e)
14 [?id=5d9dc2eb124445618959ce788086e00e](https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=5d9dc2eb124445618959ce788086e00e)

15

16 Relunched earlier this summer as the Power Improvements Map (PIM), the
17 updated tool provides localized information about current, planned and past
18 infrastructure repairs and upgrades. This means that anyone in the Company’s
19 electric service territory can enter a county, city, zip code or personal address into
20 the map and see what grid improvement work is currently in progress, planned over
21 the next two years or completed over the past three years. The map provides a
22 localized view of reliability performance for a given area after the end of each
23 calendar year, beginning with 2023. By using the PIM, all stakeholders including
24 elected and appointed officials, community leaders, regulatory officials,
25 environmental justice advocates, customers, along with the media and others, can

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1 see the work the Company is doing and in a format that is accessible and
2 transparent. The Power Improvements Map is accessible through the Company's
3 website, and can also be found directly at:

4 <https://dteenergy.com/powermap>

5

6 **Q104. Are there other efforts underway to help address AA Witness Stults request**
7 **to improve early-stage project coordination?**

8 A104. Yes. In the third quarter of 2023, a new permitting team was created within the
9 Project Management Office³⁹. The new team has six permit specialists, as well as
10 an Michigan Department of Transportation (MDOT) Coordinator, and supervisor.
11 The team is focused on building permitting expertise, building external
12 relationships, and streamlining processes. Since initiation, the permit specialists
13 have been creating a playbook for each municipality that includes the specific
14 permit requirements, timelines, process, and local contacts. The permit team
15 actively coordinates work with Regional Affairs Managers to ensure alignment,
16 resolve open issues, and coordinate on joint construction opportunities where they
17 exist.

18

19 **Q105. Are there existing processes to coordinate at a county and regional level?**

20 A105. Yes. Our regional affairs managers continue to participate and present in meetings
21 with the following groups:

- 22 • Federal-Aid Committees (FAC) are comprised of representatives of local
23 governments, transit agencies and MDOT. FAC focuses on evaluating data

³⁹ PMO was discussed in Question 12 of Kryscynski revised direct testimony

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1 and recommending projects that meet regional transportation goals⁴⁰. There
2 are different FAC for the City of Detroit, Livingston County, Macomb
3 County, Oakland County, St. Clair County, Washtenaw County and Wayne
4 County.

5 • Southeast Michigan Council of Governments or SEMCOG is a regional
6 planning partnership of governmental units serving 4.8 million people in the
7 seven-county region of Southeast Michigan striving to enhance the region's
8 quality of life.

9 • Michigan Townships Association (MTA) provides a unified voice for
10 Michigan townships on both the state and federal levels and influences
11 legislation, policy and regulations by representing townships before the
12 Legislature, the executive office and state agencies.⁴¹

13 • Michigan Municipal League (MML) supports innovative work through
14 partnerships, grants and programming that creatively and intentionally
15 bring people together and build equitable community wealth.⁴²

16

17 **Q106. Is there an existing statewide process to coordinate infrastructure projects?**

18 A106. Yes, there are several ways the Company coordinates at a statewide level. First, the
19 Michigan Infrastructure Council (MIC) was formed under Public Act 323 of 2018.
20 Their mission “is to cultivate partnerships that strengthen Michigan's Infrastructure
21 to provide the foundation for public and environmental health, economic

⁴⁰ Federal-Aid Committees, available at <https://www.semco.org/federal-aid-committees#5304578-city-of-detroit>, accessed August 7, 2024

⁴¹ MTA on the Issues, available at <https://michigantownships.org/advocacy/mta-issues/>, accessed on August 7, 2024

⁴² MML Foundation, available at <https://mmlfoundation.org/>, accessed on August 7, 2024

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1 prosperity, and quality of life”⁴³. The MIC is actively working to coordinate and
2 collaborate with entities throughout Michigan. The MIC Project Portal (MiDIG)⁴⁴
3 is “intended to assist authorized infrastructure asset owners and managers, private
4 utilities, and state agencies across the State of Michigan with cross asset
5 collaboration and coordination”. DTE Electric is collaborating on the user
6 agreement with the MIC to share electric and gas capital construction projects on
7 the statewide portal.

8

9 Second, DTE Electric meets monthly with the Michigan Infrastructure Office
10 (MIO) to discuss high level coordination, primarily focused on grant applications
11 available through the Bipartisan Infrastructure Law (BIL). The MIO was formed
12 to ensure resources sent to Michigan through the BIL are used efficiently and
13 effectively.⁴⁵

14

15 Third, the Company collaborates with MDOT on larger infrastructure projects. One
16 example included in the instant case is the I-375 Reconnecting Communities
17 Project, replacing the current below-grade freeway corridor with a grade-level
18 boulevard. Two bridge examples are the 4.8kV CC: Pinegrove Substation
19 Relocation and Conversion project, which requires the relocation of Pinegrove
20 Substation to accommodate the expansion of the Bluewater Bridge, and the Gordie
21 Howe International Bridge, which required the relocation of seven and removal of
22 five subtransmission lines.

⁴³ About the Michigan Infrastructure Council, available at <https://www.michigan.gov/mic/about>, accessed on August 5, 2024.

⁴⁴ MIC Project Portal, available at <https://www.michigan.gov/mic/project-portal>, accessed on August 5, 2024.

⁴⁵ Michigan Infrastructure Office, available at <https://www.michigan.gov/whitmer/issues/michigan-infrastructure-office>, accessed on August 7, 2024

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1 The Company believes its coordination efforts at the state level are essential to
2 communicate our projects in a clear and consistent manner, not only for the
3 communities in our service area, but for collaboration and coordination with state
4 agencies and other utilities.

5

6 **Q107. Does the Company believe there is a strong benefit to working with local**
7 **governments and communities throughout the project planning and**
8 **construction process?**

9 A107. Yes. Coordination not only allows both the Company and the municipalities to be
10 more thoughtful and prudent with our respective capital investments, but it also
11 improves the overall project timeline and productivity by identifying important
12 obstacles early in the planning phases.

13

14 **Q108. Beyond the efforts described above, can coordination be further improved in**
15 **the future?**

16 A108. Yes, with the increase of Company and Municipal construction projects in recent
17 years, there are always opportunities to improve communication and coordination.
18 The Company is willing to explore improving coordination with all stakeholders
19 and would propose a series of engagements focused on identifying opportunities to
20 further enhance existing processes.

21

22 **Q109. What future disallowance does MAUI Witness Bunch recommend that the**
23 **Commission adopt?**

24 A109. On page 84, starting at line 20, Witness Bunch suggests 10% disallowance on
25 electric infrastructure investments with excavation work in the public right of way

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1 or public easements, unless the Company can prove it has made reasonable attempts
2 to coordinate work with such projects.

3

4 **Q110. Does the Company agree with MAUI Witness Bunch’s recommendation that**
5 **future project costs may be excluded from recovery if there is failure to**
6 **coordinate work?**

7 A110. No. While DTE Electric believes that work coordination is preferable, it does not
8 agree that costs should be excluded from recovery if work coordination does not
9 occur. There are many reasons why it may not be possible to coordinate work.
10 First, the Company’s investment work may need to be done sequentially and may
11 not be able to be aligned perfectly with the municipality. Second, there may be
12 regulatory requirements that do not allow for timeline adjustments. Lastly, there
13 may be times due to unforeseen circumstances, new business work as an example,
14 a project needs to be built on a short timeline, which may not allow much time for
15 coordination.

16

17 Additionally, this standard would be difficult to implement and evaluate as opinions
18 regarding what constitutes a “reasonable attempt” could vary substantially. For
19 these reasons, the Company recommends that the Commission reject this proposal.

20

21 **Q111. Are there other recommendations from MAUI Witness Bunch, or Ann Arbor**
22 **Witness Stewart?**

23 A111. Yes. Below is a summary of their recommendations and rebuttal points

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1

Table 10 Municipal Coordination Recommendations

2

Witness	Testimony	Rebuttal Point
Bunch	<p>“In most cases, the requirement regarding local governments could be met by reference to publicly-available CIPs with very little effort.” Page 85 lines 4-5</p> <p>Furthermore, as stated by Witness Bunch, “In most cases, local governments make them readily available through their websites. If a CIP were not available on a website, a utility could easily get a copy by contacting the local government – no FOIA request is needed.” on page 83 lines 10-12.</p>	<p>Witness Bunch’s testimony implies a central location for all municipal plans which does not exist. Alternatively, the Company has made its construction efforts publicly available on the Power Improvements Map for all 415 municipalities in its service area.</p>
Bunch	<p>“The Commission should require DTE to demonstrate that it prioritizes locations of infrastructure undergrounding and underground maintenance projects, in part, by identifying local-government infrastructure projects that require excavation with which the DTE projects could be co-located and -scheduled.” Page 85 lines 6-9</p>	<p>DTE Electric prioritizes the location of projects and maintenance to support providing electricity to our customers first. DTE Electric strives to proactively work with municipalities to collaborate on co-location and scheduling, while still providing service to our customers.</p>
Stewart	<p>“Often, the way the City staff receives notice of a planned DTE project is through the Company’s application for a right of way permit. Notice at this late stage of a project is not conducive to meaningful coordination or collaboration.” Page 6 lines 1-3</p>	<p>The Company is actively improving its coordination efforts and has made its construction efforts publicly available on the Power Improvements Map for all 415 municipalities in our service area.</p>

3

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1 **Rebuttal Issue 13: Distribution Pilots and Recommendation**

2

3 **Q112. Beyond the pilots proposed by CEO Witness Volkmann which have been**
4 **discussed above, have other witnesses proposed additional distribution pilots?**

5 A112. Yes, two additional pilots proposed were proposed in testimony:

6 1. "...an underground geothermal network be evaluated as a pilot project for
7 at least one resilience microgrid in Highland Park, with community
8 participation as to its location, possibly Parker Village" was recommended
9 by DAAO Witness Makhijani on page 59, lines 15-17

10 2. "The Commission should direct the Company, in its next rate case or
11 demand response case, to propose a pilot of geo-targeted incentives for
12 customer-owned distributed energy systems (including batteries)." was
13 recommended by GLREA Witness Richter, page 54, lines 11-13.

14

15 **Q113. What is the Company's current pilot status and process?**

16 A113. The Company is committed to completing the NWA pilots underway and
17 communicating lessons learned and results in order to inform discussions on how
18 to scale the piloted technologies. As noted in section 9.1.2 of the Distribution Grid
19 Plan (Exhibit A-12, Schedule M8), the Company has already incorporated NWA
20 options into its grid planning. Engineering has developed a screening process to
21 determine which load relief projects might be good candidates for a NWA, and then
22 if the project is a good candidate, works with planning engineers to determine the
23 appropriate grid solution.

24

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1 Although the Company doesn't have current plans to expand the set of NWA pilots,
2 it will continue to evaluate promising new technologies, and use the Commission's
3 recently developed expedited pilot process, February 23, 2023 order in Case No.
4 U-20898, for consideration of any future potential pilots. The expedited pilot
5 process does have provisions for stakeholder engagement.

6

7 **Q114. Were there other distribution recommendations?**

8 A114. Yes. GLREA Witness Rafson recommended "The Commission should specifically
9 allow nanogrids and microgrids" on page 13, line 11 of their testimony.

10

11 **Q115. Does the Company have any concerns about this recommendation?**

12 A115. Yes. This proposal impacts tariffs and other operational and significant safety
13 issues. If the Commission decides there is merit in pursuing this proposal further,
14 it should be addressed in separate interconnection rules forum.

15

16 **Q116. Does this conclude your rebuttal testimony?**

17 A116. Yes, it does.

1 JUDGE WALLACE: And we will be admitting
2 Exhibits A-13, A-23, A-43, and all of the associated
3 schedules when we, at the -- after we end cross and bind
4 in the Company's case. So Ms. Andrews, please go ahead.

5 MS. ANDREWS: Thank you.

6 CROSS-EXAMINATION

7 BY MS. ANDREWS:

8 Q Good morning, Mr. Kryscynski. Can you hear me O.K.?

9 A I can. Good morning.

10 Q As I understand it, you manage distribution operations
11 for DTE and oversee long-term grid modernization and grid
12 planning; is that right?

13 A I would not characterize it that way. I do not manage
14 distribution operations for DTE. I do, as you suggest,
15 manage capital planning for DTE and also the DO or
16 distribution-operations-related regulatory matters.

17 Q O.k. So when I look at page 2, line 24, and says you're
18 managing distribution operations regulatory activities,
19 that's not the same as distribution operations, correct?

20 A I am part of the distribution operations team, but I am
21 not managing all of distribution operations.

22 Q O.K. Thank you for the clarification. The purpose of
23 your testimony, among other things, is to provide a
24 distribution overview and introduce other distribution
25 witnesses; is that right?

1 A That is correct.

2 Q Among other topics, you support the Company's global
3 prioritization model or GPM, right?

4 A That's correct.

5 Q You testified related to the GPM in DTE's last rate case,
6 21297; do you recall that?

7 A I do.

8 Q I am afraid -- so I'm going to ask you a few questions
9 about the GPM, and unlike my pred -- Mr. Bzdok, who I
10 believe asked you questions in the last rate case, I will
11 probably not be as smooth, and for multiple reasons, so
12 please bear with me because I want to get into some of
13 the details about the GPM and it might be a little
14 clunky.

15 Do you have access to the SharePoint for
16 this hearing?

17 A I do.

18 Q Do you have access to the folder entitled MNSC Hearing
19 Exhibits for Kryscynski?

20 A I do.

21 Q O.K. And you're able to see and open the documents in
22 that folder O.K.?

23 A I have opened some of them to test, but I have not opened
24 all of them. Assuming everything continues to work, yes.

25 Q O.K. So I'd like to understand a little bit more about
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1 the GPM. This is a tool that DTE developed; is that
2 right?

3 A That is correct.

4 Q And about how long ago did DTE first develop the GPM?

5 A I don't know for sure. I believe, you know, it's been
6 presented I believe in several rate cases now. I would
7 say, if I was to tender a guess, five to eight years ago.

8 Q O.K. And DTE, the tool was developed to prioritize or
9 rank strategic distribution programs and projects, right?

10 A Correct.

11 Q So it does not make any effort or attempt to prioritize
12 strategic programs and projects relative to base or new
13 business projects and programs?

14 A No, it does not.

15 Q O.K. So just at a high level, the GPM has ten impact
16 dimensions that correlate to project benefits, right?

17 A That is correct.

18 Q Can you give me -- can you list off the impact
19 dimensions? Do you -- refer us to your testimony where
20 you list them off.

21 A Yeah, I probably could, but I think it will be quicker
22 and easier if I refer to my testimony, so if you give me
23 one second, I will flip to that section.

24 Q Sure.

25 A All right.

1 Q So I'm going to look at -- direct you to page 57, there's
2 Table 6.

3 A Yes. Would you like me to read off the dimensions?

4 Q There's no need to, I think it's clear in your testimony,
5 there are -- the ten impact dimensions are listed in the
6 first column on Table 6, right?

7 A That is correct.

8 Q And these impact dimensions correlate to the project
9 benefits, correct?

10 A Correct.

11 Q DTE, the model, the GPM will score each program or
12 project under each of these impact dimensions, correct?

13 A Correct.

14 Q And then the result is a score that allows the Company to
15 prioritize among its strategic capital, strategic
16 programs; and to be clear, these are all capital
17 programs, right, O&M is not included?

18 A That is correct.

19 Q Tree trimming would be the only -- tree trimming used to
20 be included in the GPM; is that right?

21 A We have run tree trimming in the GPM before. My -- I
22 cannot remember if in the past we've included it in an
23 actual rate case filing.

24 Q O.K. Since the last rate case where you testified in
25 support of a GPM, there have been a few changes to the

1 GPM, right?

2 A That is correct.

3 Q You discuss these on pages 58 and 59 of your testimony?

4 A That is correct.

5 Q So just to summarize, DTE added three new impact
6 dimensions, SAIFI, investment in EJ communities, and then
7 over -- capacity -- sorry -- load relief was split into
8 overload relief and capacity relief; is that a fair
9 summary?

10 A Yes. Let me just repeat.

11 Q Yes.

12 A Load relief was split into overload relief and capacity
13 relief, SAIFI was added, and investment in EJ communities
14 was added. I will also note to my previous answer that I
15 believe changes are also discussed in part on page 60 of
16 my direct testimony.

17 Q O.K. Thank you. What does SAIFI mean, just for context?

18 A SAIFI is frequency, so it's number of customer
19 interruptions divided by total customers on the system.
20 Let me see if I can remember exactly what the acronym
21 stands for.

22 Q System Average -- start with System Average?

23 A Yeah, System Average, I think Interruptions Frequency
24 Index, if I recall, subject to check.

25 Q That's fine, I don't think anything you could say on the
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1 record today will change the definition of SAIFI for
2 purposes of this case luckily.

3 A O.K.

4 Q DTE also since the last rate case changed the weighting
5 for the impact dimensions, correct?

6 A Correct.

7 Q So before, in the last iteration at least, there were
8 weighting up to 10 points or 10 times for some impact
9 dimensions and ranges in between 1 and 10 for each impact
10 dimension, correct?

11 A I believe that is correct, yes.

12 Q And the change that the Company made, which is reflected
13 in page 59, Table 7, of your direct testimony is that
14 there are now just three weightings, correct, 1, 2, or 3?

15 A That's correct.

16 Q So then on page 65 of your direct testimony, you provide
17 the summary of the Top 50 Strategic Capital Programs and
18 Projects Based on the GPM?

19 A Correct.

20 Q Before we dig into the top 50 list, I just want to
21 identify a couple of other changes since the last, since
22 you last testified on the GPM. In the last case, do you
23 recall that the GPM was not public, it was not produced
24 in the case?

25 A The entire model was not produced in the case, that's

1 correct.

2 Q The top 50 results and the scores were produced, but not
3 the model itself, correct?

4 A Subject to check, yes, I believe that is correct.

5 Q But DTE did provide a copy of the GPM in this case, and
6 that's Exhibit A-43 HH4 of your rebuttal testimony,
7 correct?

8 A Let me just check, but that sounds correct. We provided
9 it as both a workpaper and then I believe, I know an
10 exhibit in my rebuttal testimony. Just trying to check
11 the number. Yes, GPM was HH4, correct.

12 Q O.K. And you produced it, you just mentioned, as a
13 workpaper in your initial application with the case,
14 correct?

15 A That is correct.

16 Q Why did DTE decide to produce a copy of the GPM in this
17 case?

18 A We received a direction from the Commission that they
19 would, based on our last case, the transparency was
20 something that was important, and we are listening to the
21 Commission and complying.

22 Q And who made the decision to not produce the GPM in prior
23 cases?

24 A I do not know.

25 Q Was it your decision to produce the GPM as a public
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1 workpaper and an exhibit in this case?

2 A I believe it was a collective decision, and I was
3 included.

4 Q Go ahead. And what were the factors that you, that
5 weighted for and against producing that as a public
6 document, the GPM, the actual model in this case?

7 MS. HAYDEN: I'll just place an objection
8 to the extent that the question is asking for privileged
9 communications.

10 Q (By Ms. Andrews): Without revealing attorney/client
11 information.

12 A I'd have to consult with my attorney, I don't know if I
13 can answer that question without revealing attorney/
14 client information.

15 Q O.K. Fair enough. Since -- also since the last rate
16 case that you supported the Global Prioritization Model,
17 DTE also filed an updated Distribution Grid Plan; is that
18 right?

19 A That is correct.

20 Q That we can refer to as the DGP?

21 A Yes, please.

22 Q And that was filed in late September 2023 in a docket, a
23 Commission docket, right?

24 A Yes. And if you're all right, we can call that the 2023
25 DGP, that would be helpful.

1 Q O.K. And you sponsored the 2023 DGP as an exhibit in
2 this case?

3 A That is correct.

4 Q O.K. So let's go back to the top 50. Oh, before we do
5 that, let's -- I want to ask a couple of preliminary
6 questions. First I'd like to understand a little better
7 about how the GPM considers costs in its analysis in the
8 model. You indicate on page 55 of your direct testimony
9 that the benefits are weighted against costs in all but
10 two impact dimensions, regulatory compliance and
11 investment in EJ communities, right?

12 A Correct.

13 Q What does it mean to not weigh benefits against costs for
14 those two impact dimensions, what is the distinction for
15 those two impact dimensions?

16 A What it means is we don't consider costs in those two
17 impact dimensions. Score is not impacted by cost.

18 Q O.K. And then you further indicate that of the remaining
19 eight dimensions, so all the dimensions except regulatory
20 compliance and investment in EJ communities, two of those
21 are based on costs avoided, right, on, measured in costs,
22 the score is a cost outcome, it's a score -- let me see
23 if I can get that straight. The score for two of the
24 impact dimensions is a cost, which is the O&M avoided and
25 the capital avoided, those are measured in dollars,

1 right?

2 A I wouldn't characterize it that way.

3 Q So on page 55 of your direct testimony, pages -- lines 10
4 to 11, it says only two of the GPM captures, O&M
5 avoidance and capital avoidance, are measured in monetary
6 terms. All other dimensions are quantified in
7 non-monetary terms. What is that distinction between
8 monetary terms and non-monetary terms?

9 A Sure. Let me explain. So your question previously I
10 believe was are the scores dollars. No, the scores are
11 not dollars, because what we do is we look at cost
12 avoided, which is in dollars, divided by total cost of
13 the projects, also in dollars. The dollars cancel out in
14 that division, the units cancel out, and therefore you're
15 left with just a score, right. But the benefits, to your
16 point, are measured in dollars.

17 Q The benefits are measured in monetary terms as opposed to
18 non-monetary terms like wires down?

19 A Correct.

20 Q O.K. So then of -- so that was two impact dimensions
21 have no dollars at all, two impact dimensions have scores
22 that are measured in monetary terms. The other six
23 impact dimensions, how does the Company consider program
24 and project cost in the scoring?

25 A So let's take SAIDI as an example. What we will do is

1 look at the number of SAIDI minutes that a program or a
2 project will reduce. So if it saves ten minutes, let's
3 say, of (inaudible) --

4 COURT REPORTER: I'm sorry. Saves ten --
5 you're a little fuzzy. So if it saves ten minutes of?

6 A Total system SAIDI, so if it -- apologize for being
7 fuzzy. So if it saves ten minutes of total system SAIDI,
8 that would be the benefit portion of that score, and then
9 we would divide it by the cost to achieve those ten
10 minutes of system SAIDI, so the cost of the project or
11 the cost of the program.

12 Q (By Ms. Andrews): So in effect, the score for six of the
13 dimensions is, for every million dollars spent, we can
14 achieve X SAIDI minutes or X wires down or X whatever the
15 measure is?

16 A Yes, basically, yes.

17 Q So for the six impact dimensions that are not the four
18 we've just talked about, the ones that we don't put any
19 costs on and the two that are scored in monetary terms,
20 so to speak, the score is a, the unit of the score is a,
21 is the measure of the benefit, the wires down or the
22 SAIDI benefit or the SAIFI benefit, correct? It's not
23 the dollars, it's the number of minutes for every dollar,
24 not -- or every million dollars, not the number -- right?

25 A It's a ratio, right. So it's the minutes divided by the

1 dollars, right, of the investment required to get those
2 minutes, right. And then the score is, goes a step
3 further. When we index, we index those ratios relative
4 to each other, that's the, that's the score for that
5 dimension.

6 Q O.K. So we've mentioned a couple of times that the GPM
7 ranks both programs and projects, right?

8 A That is correct.

9 Q So an example -- what's an example of a program that
10 might be ranked by the GPM?

11 A (Inaudible).

12 COURT REPORTER: I'm sorry. Say that
13 again, please?

14 A PTMM.

15 Q (By Ms. Andrews): And what does PTMM stand for, just for
16 the record?

17 A Pole top maintenance and modernization.

18 Q O.K. And then an example of a project might be the
19 conversion of a single substation?

20 A That would be correct.

21 Q And the GPM will rank programs and projects irrespective
22 of whether it's a program or a project, right?

23 A Yes, the GPM ranked both programs and projects using the
24 same framework, correct.

25 Q And the PTMM program, just to use one example, is a

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1 series of, it's a number of circuits or circuit miles per
2 year are treated within a program based on spending and
3 based on various factors, and so the program is a
4 compilation of all of the circuits or circuit miles or
5 circuit, whatever the unit is that's being treated; is
6 that fair?

7 A The way the GPM ranks a program, because something like
8 PTMM in theory is a program that goes on indefinitely, a
9 standard maintenance program for our utility as well as,
10 as far as I'm aware, all utilities, it is something that
11 we take a five-year look at. So for the GPM, we look at
12 the benefits expected over five years as well as the cost
13 over five years, and that assumes that the program is
14 expected to go five years.

15 Q DTE runs the model, the GPM, on an, approximately an
16 annual basis; is that right?

17 A The GPM --

18 Q And I don't want to --

19 A Yes, the GPM is run on an annual basis, correct.

20 Q So when DTE runs the GPM, does it become sort of fixed
21 until next year, or is it sort of -- what does it mean to
22 run it year by year; is there sort of GPM season where
23 DTE, you know, does all of the program updates? How does
24 that -- what does it mean to run it annually, given the
25 nature of the model?

1 A Sure. So what we re doing is we are adding new projects
2 or programs into it or removing old projects or programs
3 that have concluded.

4 Q And is there sort of a cutoff date for when that's done?

5 A I'd say it can vary depending on the year and various
6 other factors.

7 Q O.K. Would you agree that the GPM is not decisive in the
8 terms of if a project scores high, DTE will execute it,
9 if it scores low, DTE will not execute it, there's
10 subjectivity even whether a high-ranking GPM moves
11 forward or a low-ranking GPM project moves forward or
12 doesn't?

13 A I would say that generally all high-ranking GPM programs
14 do move forward, at least to the extent the Commission
15 approves them. Low-ranking programs may or may not move
16 forward, because while the GPM does a good job of
17 capturing many of the benefits for projects, there are
18 benefits outside of the GPM that -- the GPM cannot
19 capture holistically everything about a project, so there
20 might be low-scoring projects or low-ranking projects
21 that still have another reason to be constructed or
22 invested in outside of the standard ten-dimension
23 framework.

24 Q Would you say that a high-ranking project will move
25 forward and a low-ranking project may also move forward?

1 A Generally that has been my experience, yes.

2 Q Is there any reason a high-ranking program or project
3 would not move forward?

4 A Well, an example of a time that we wanted to invest more
5 in a high-ranking program than we were able to was in
6 this most recent, the past rate case, 21297, we wanted to
7 invest more in the PTMM program than was approved, so
8 the --

9 Q So --

10 A Go ahead.

11 Q So just to be clear, the GPMM -- the GPM is not telling,
12 it's not telling us how much to spend on pole tops,
13 right, it's telling how PTMM ranks relative to another
14 project over a five-year period?

15 A For programs, they are measured over a five-year period,
16 a project could be measured, will be measured over the
17 life of the project, so it's giving us a relative benefit
18 of one program or project versus another program or
19 project.

20 Q The score for PTMM does not evaluate whether, let's say,
21 the dollars per or the benefits per dollar, it doesn't
22 tell you whether that benefit will -- it assumes that
23 benefit is constant, right, it's uniform, it doesn't
24 matter whether it's the first day of the program or last
25 day of the program, that's the expensed benefits per

1 dollar spent, right?

2 A We look at it over that whole five-year period for all
3 circuits that we expect to be invested in over that
4 five-year period.

5 Q In your direct testimony on page 63, you acknowledge that
6 scores for the same project may change year over year
7 within the GPM. I'm looking at -- sorry -- page 63,
8 lines, starting at line 14.

9 A Give me one second to get there. I'm here, let me just
10 read it, please. Will you please restate your question?

11 Q Score, or rankings, I guess I should say, for a project
12 may change year over year in a GPM run?

13 A If we get new information, that is correct.

14 Q What's -- give me an example of new information that
15 would change a ranking or a score for a program or a
16 project.

17 A So the PTMM program, if we're expecting a 30% reduction
18 in equipment event outages and we see a 40% increase in
19 equipment event outages, then we would see an expected
20 increase in SAIFI production, SAIFI reduction, I would
21 imagine cost avoidance, and, you know, I'm not going to
22 go through every dimension, but it would change some of
23 the dimensions, and that would increase the score, as an
24 example.

25 Q So the PTMM program didn't change year over year, but the
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1 equipment event outage changes and, therefore, the PTMM
2 score may change?

3 A If we get new information about a program or project that
4 leads us to think that we'll get more or less benefits,
5 we would update that in the GPM.

6 Q O.K. I'm just taking notes so that I can remember this
7 later. O.K. Sorry for the delay.

8 In your testimony, you indicate that
9 keeping, you want to keep scores, scoring relatively
10 consistent year over year. What's the interest in
11 keeping scoring relatively consistent year over year?

12 A Will you -- I'm sorry, will you restate that question?

13 Q In your testimony, you indicate that keeping, you try to
14 keep scoring relatively consistent year over year.

15 A So in my testimony I say -- I'm just going to read it so
16 we, for context. However, to keep scoring relatively
17 consistent year over year, the entire project cost and
18 entire project benefits are still used when scoring the
19 project or the program, although the project cost and
20 benefits will be adjusted for known changes. Examples
21 include cost increases or more benefits than forecast.

22 Q O.K., we'll come back to that, and I think it will be
23 helpful to have an example in the program to look at that
24 further. On page 65, we referenced earlier the top 50 in
25 the latest GPM run. When was this Table 9, page 65, when

1 was this run of the GPM run, so to speak, when did you
2 compile this table?

3 A I do not remember the exact date.

4 Q Range, ahead of your testimony in this case? If your
5 testimony was filed in February, would this have been
6 when?

7 A I would say, my best guess would be sometime between
8 January and when my testimony was filed. That would be
9 my best guess, subject to check.

10 Q O.K. Would you say that you, the Company runs the GPM in
11 support of or to inform its rate case application?

12 A I would say that we run the GPM to support our investment
13 decisions.

14 Q O.K. Which are reflected in the rate case filing?

15 A Investment decisions are reflected in the rate case
16 filing.

17 Q O.K. Let's refer to the distribution, the '23 DGP, which
18 is Exhibit A-23 Schedule M.

19 A Let me change binders here. I've got a lot.

20 Q O.K., yep, there's a lot of paper.

21 A Lot of paper. All right. What page would you like to
22 look at?

23 Q I'm going to direct to you page 259, which is Appendix F.

24 A All right, I'm there.

25 Q So just for context, Appendix F, page 259 of the 2023 GPM

1 shows the top 50 strategic capital programs and projects
2 based on the GPM, right?

3 A Right.

4 Q And it spans about three pages of the DGP?

5 A That's right.

6 Q So the DG -- I'm sorry. The 2023 DGP was filed in late
7 September, right?

8 A It was filed --

9 Q Subject to check?

10 A -- at the end of September, correct.

11 Q When would the GPM have been run for the DGP, the 2023
12 DGP, more or less?

13 A My guess is we probably would have run it a few times
14 during the creation of the GPM. The GPM, the creation of
15 GPM usually occurs over a year or more timeframe, it's a
16 big document, and so we would likely run the GPM more
17 than once.

18 Q The top 50 shown in the '23 GPM, the sort of ultimate run
19 of the GPM for purposes of the DGP, sometime before
20 September 29th, sometime in the summer of 2023?

21 A Most likely, subject to check, it would have been
22 sometime in the summer would have been the run that
23 resulted in this table.

24 Q Why would you run it multiple times during the
25 development of the DGP?

1 A Well, we're always updating it as we get new projects or
2 programs, it's a fluid model.

3 Q It's fluid during the development of the DGP?

4 A It's fluid at all times.

5 Q It's fluid during the development of the rate case?

6 A It is fluid at all times. If we get a new project or
7 program, we will enter it into the DGP to see how it
8 ranks.

9 Q Would you update -- would you make changes within
10 projects, so not new projects or programs but existing
11 programs, would those also be treated fluidly in the GPM?

12 A If we get new information, we will update the DGP -- or
13 the GPM.

14 Q So. The GPM. Sorry, we're talking about the GPM. So at
15 all times, the GPM is being updated to reflect new
16 programs, new projects, new information about existing
17 programs and projects, fair?

18 A Fair.

19 Q In the last DTE rate case, in your direct testimony you
20 supported a top 50 list from the DG -- the GPM, and I'm
21 going to refer you to what's been labeled as Exhibit
22 MEC-36, unless you happen to have all of your documents
23 from the last rate case handy. Exhibit MEC-36 --

24 A Yes, I have it open.

25 Q -- should be a page out of the transcript from 21297. Do

1 you recognize that?

2 A I do.

3 Q And would you agree that this Exhibit MEC-36 appears to
4 be the top 50 results that supported DTE -- or GPM run in
5 support of DTE's investment plan for Case No. 21297?

6 A Subject to check, yes.

7 Q The last rate case was filed, if you will take my word
8 for it, on February 10, 2023. Would you agree that the
9 20 -- I'm sorry -- MEC-36 is the iteration of the GPM
10 sometime in early 2023?

11 A I honestly don't remember, I'd have to check. It sounds
12 like a reasonable assumption, but I do not know.

13 Q Would you agree that the top 50 GPM filed in the last
14 case reflects the investment plan that the Company
15 proposed in its last rate case?

16 A I would not characterize it that way.

17 Q Would you agree that the investment plan that the Company
18 proposed in its last rate case reflected the GPM scores
19 from, that you testified in support of in the last rate
20 case?

21 A I would agree that this list here is the top 50 programs
22 and projects that the GPM scored, which the Company then
23 uses to evaluate and prioritize investments.

24 Q O.K. So in the course of about a one-year period from
25 early 2023, mid 2023 for the DGP, 2023 DGP, and then the

1 filing of this rate case, the Company has produced three
2 top 50 GPM lists; is that right?

3 A That is correct.

4 Q O.K. And each iteration of the DG -- GPM top 50 list has
5 some differences; is that fair?

6 A That's fair.

7 Q Let's take in order from 21297 top 50 list, so that's
8 MEC-36, what was the top ranked project or program?

9 A ADMS: DMS/OMS.

10 Q O.K. And then for the DGP, Exhibit A-23 Schedule M8,
11 page 59, what was the top program or project?

12 A This is the DGP one you're asking about?

13 Q Yep.

14 A On page 258 of the DGP, the top program is pole and pole
15 top hardware, PTMM.

16 Q O.K. And then so that was about summer of 2023 I think
17 we agreed, somewhere, subject to check, around then?

18 A I agree, subject to check.

19 Q And then in your testimony in this case, page 65, Table
20 9, what is the top project?

21 A Top project is, page 65, correct?

22 Q Yep.

23 A It is ADMS: DMS/OMS.

24 Q O.K. So in the course of a year, ADMS went from top to
25 not ranked back to the top, and you can, subject to

1 check, look at DGP for my assertion that it was not
2 ranked?

3 A I would not characterize it that way.

4 Q What would you characterize it? How would you
5 characterize it?

6 A Well, the GPM, the OMS ADMS -- ADMS: OMS/DMS is not
7 ranked, it is a forward-looking document. This, by this
8 point, there is not significant investment left in that
9 system if we are assuming it's complete or largely
10 complete at this point. So it is, it was chosen not, we
11 chose not to rank it because there wasn't future
12 investment, whereas both the previous rate case document
13 and this rate case document have exhibits that date back,
14 back to when this ADMS: OMS was receiving significant
15 investment. In this particular case in 2022, I believe
16 2023, but particularly 2022, we were investing in that,
17 and therefore it needed to be included in the GPM in both
18 of these rate cases where it did not and should not have
19 been included in the GPM.

20 Q So whether to rank a project or a program depends on the
21 purpose for which the GPM is being used?

22 A The whole point of the GPM is to rank investment, rank
23 our investments, right, our strategic investments. And
24 so in the GPM, we were looking forward and we are ranking
25 investments that actually have spend looking forward.

1 Q So which drives which, does spending drive GPM projects
2 or do GPM projects drive spending decisions?

3 A I don't -- can you rephrase that question?

4 Q Sure. From what I understand, whether to rank a project
5 depends on whether the Company plans to spend on the
6 project?

7 A We would not put a project in the GPM that's already
8 complete.

9 Q But you did put the project in the GPM for the rate case
10 even though it's already complete?

11 A Right, because it's supporting investment that's in the
12 rate case.

13 Q So the GPM, the projects in the GPM are included in the
14 GPM to support the investments in the rate case?

15 A For the rate case run, we put all investments that are in
16 the rate case into the GPM. The GPM is a forward-looking
17 document, and so we are only putting investments in it
18 that are forward looking that we plan to invest in.

19 Q I understood the ADMS does not anticipate forward
20 investment in this rate case.

21 A The ADMS anticipates investment that is stated in this
22 rate case.

23 Q Which is prior-year investments?

24 A I would have to check to confirm that. ADMS is supported
25 by Witness Hartwick, she would be the best person to talk

1 in detail about the ADMS.

2 Q O.K. So if a project has spending, then it will be
3 included in the GPM?

4 A If a project has spending and grid benefits, we would
5 rank it in the GPM, correct.

6 Q Spending and grid benefits or just spending?

7 A Spending and grid benefits. The --

8 Q So ADMS has grid benefits for both DGP and rate case
9 purposes, right?

10 A I guess I don't understand your question.

11 Q Sorry. I'm trying to distinguish between the grid
12 benefits and the spending.

13 A What are you trying to distinguish about that?

14 Q Which -- you know what, I think we're going to move on
15 because I'll save those questions for Ms. Hartwick
16 tomorrow.

17 A O.K.

18 Q And I think we'll have some more questions in the context
19 of the GPM.

20 MS. ANDREWS: Your Honor, at this point I
21 am going to dig into the model, I'm happy to start that,
22 or we could take a short break.

23 JUDGE WALLACE: Why don't we go ahead and
24 take a ten-minute break. So it's -- well, 13-minute
25 break. 9:57, so let's be back here at 10:10.

1 MS. ANDREWS: Great. Thank you.

2 (Recess from 9:57 a.m. until 10:13 a.m.)

3 JUDGE WALLACE: All right. Then we're
4 back on the record. Please continue, Ms. Andrews.

5 MS. ANDREWS: Thank you.

6 Q (By Ms. Andrews): Mr. Kryscynski, in the Share hearing
7 folder for this case is a copy of the Excel, a read-only
8 exhibit, for A-43 Schedule HH. Do you see that?

9 A Let me look.

10 Q Do you have a, your copy of the -- it should be the same,
11 so --

12 A So Exhibit A-43 HH?

13 Q 4.

14 A HH4. Yep, I'm opening it up now.

15 Q And to be clear, the folder has the PDF, which I believe
16 is just a link to the document, and then the document is
17 also in the folder. Are you with me?

18 A No. Will you please restate that?

19 Q I'm sorry. The hearing folder has a PDF with the name,
20 with the title Exhibit A-43 Schedule HH4, a PDF that just
21 links to the Excel, I think you referenced that in your
22 bind-in of your testimony.

23 A Yes. And but you wanted me to open the Excel version; is
24 that correct?

25 Q Yes, correct.

1 A All right.

2 Q O.K. So we're just going to walk through the tabs, the
3 model from, basically from left to right just for
4 orientation purposes. The first tab is a list of the
5 top, of the projects as they were ranked in this
6 iteration of the GPM, correct?

7 A Subject to check, yes.

8 Q And there's also a graph that shows them, their relative
9 ranking to each other, correct?

10 A Correct.

11 Q The next tab is a different visual depiction of the top
12 50 formatted, so to speak, for the rate case?

13 A Formatted in a table, yes.

14 Q And that's the same table that's in your testimony?

15 A Subject to check, yes.

16 Q The third tab is labeled A-23 M14, this is the workpaper
17 or the Excel version of an exhibit that provides scores
18 for all the projects and programs that were ranked,
19 correct?

20 A Subject to check, correct.

21 Q And we can see the scores by, each GPM score by impact
22 dimension in row 9, right?

23 A By impact -- the impact dimensions are in row 9, if
24 that's what you're asking.

25 Q Yep, that's all I'm asking. The next tab is the GPM

1 results, the green tab in the Excel. Do you see that?

2 A Yes.

3 Q This includes the same score information as in the
4 preceding tab but in, formatted into the table, right,
5 subject to check?

6 A Subject to check, yes.

7 Q So for each program or project that's in the ranking, it
8 provides the score in each of the ten impact dimensions,
9 the total score, and some other information about the
10 project or program?

11 A Yes, correct.

12 Q All right. If we scroll to the far right of the GPM
13 results tab, starting at column AF --

14 A Yes.

15 Q -- what are we looking at here, what is this a list of?

16 A Let me see if I can edit to look at the formula, hold on.
17 This particular file is not letting me -- let me see
18 if -- do you mind if I take a minute to try and open a
19 different version of this?

20 Q No problem.

21 A O.K. Might take me a second, so just bear with me.

22 JUDGE WALLACE: Let's go off the record
23 for a couple minutes.

24 (Off record, 10:19 a.m. through 10:24 a.m.)

25 JUDGE WALLACE: Back on the record.

1 MS. ANDREWS: Thank you, your Honor.

2 Q (By Ms. Andrews): Before the break, I asked you,
3 Mr. Kryscynski, what's the difference between the list in
4 the table in blue on the left side of the tab and versus
5 the list sort of starting in column AF on the right side
6 of the tab?

7 A What I'm going to have to do is look through this and
8 work through the formulas here to give you the
9 appropriate answer.

10 Q O.K. Can I ask you a few followup questions, that might
11 refresh, or if they are beyond your comfort, you may say
12 so?

13 A Yes, absolutely.

14 Q So the list, let's just say on the left list formatted in
15 blue, just scrolling through the list, looks to me to be
16 about 147, the list continues through row 147; do you see
17 that?

18 A Scrolling down. The -- you're talking about the list on
19 the left now? Apologize.

20 Q Yeah, yep.

21 A That is correct.

22 Q So it appears to be the 138 programs that are included in
23 exhibit, in the preceding tab, I believe there were
24 138 -- no, not quite. That's not true. There's 138
25 projects ranked on the left side of the model, it says

1 138 in row 8, column B, which seems to reflect the number
2 of projects or programs ranked, subject to check?

3 A I would agree with that assessment, subject to check.

4 Q And then if we scroll over to the, to the right side of
5 the column starting in column AF, just scrolling through
6 the bottom, that's populated, it looks like that list
7 includes 198 -- 197 rows of information, rows, some of
8 those rows include headers and such?

9 A I would say, quickly, that there are 189 rows with titles
10 in column AK, I believe.

11 Q So presumably, subject to check, the 138 rows on the left
12 side of the tab are a subset of the 189 rows of
13 information on the right side of the tab?

14 A I would have to check to confirm that answer.

15 Q O.K. So if we look at column AJ, and I don't want to
16 make edits while we're talking, but I think you can
17 toggle column AJ. What -- let me just ask, what is
18 0=off1=, and I suspect underneath that little arrow it
19 says on, what does that mean?

20 A I would have to trace back through the model on this.

21 Q Does the mobile fleet program appear in the list of 138
22 programs?

23 A Let me check. It does not appear to appear in the list
24 on the left-hand side in column D.

25 Q How about 4.8 kV hardening in row 16 where there's a 1 in

1 column AJ, does that appear on both sides of the tab, of
2 the tab on both the left-hand and the right-hand lists?

3 A I believe it probably does, but give me second to check.
4 Yes, it does, it appears on both sides, correct.

5 Q Looking over at column AY, some programs or projects have
6 -999 in the score in the, what is that called, score for
7 ranking; do you see that?

8 A Yes.

9 Q Subject to check, would you agree that the -999
10 correlates to rows where column AJ is zero?

11 A Subject to check, that is what it appears, correct.

12 Q Based on the information in the score for ranking, why
13 would score for ranking be -999?

14 A I believe this is just a tab, so we can rank programs
15 over on the left-hand side, so probably just putting
16 these at the bottom because it has a score of zero.

17 Q Thank you. O.K. So would you agree that, subject to
18 check, column AJ allows the Company to toggle a program
19 to be included or not included in the list of GPM
20 results?

21 A I would have to check to, I'd have to check and walk
22 through the formulas to figure out exactly what that
23 column does, as I previously stated.

24 Q Who would you need to check with?

25 A I would check with my support team.

1 Q And can you do that at our next break or over lunch?

2 A I can see if they're available to do that.

3 Q O.K. So looking at the disconnect switcher replacement
4 program in row 13, that project does have a total score
5 as opposed to zero, the projects above and below it. Why
6 would that -- why would a project with a score -- I
7 understand why a project with a zero would be ranked
8 -999, but why would a project with a score, positive
9 score, receive a score for ranking of -999?

10 A Looking at it, I -- I do not have the exact answer to
11 that question. I would have to check with my support
12 team.

13 Q O.K. Similarly with row 36, we see the flood defense
14 program has a score of 196.

15 A What row?

16 Q It's row 36. Yep, you're there, I can see you moving
17 around in the exhibit.

18 A Yes.

19 Q Do you have any understanding as to why this project or,
20 has a score but is not ranked?

21 A I would again like to check with my support team on that.

22 Q Who would make decisions about whether to rank or not
23 rank a project or a program?

24 A Collectively, myself and my support team.

25 Q Who's on the support team?

1 A I have a manager of strategy reports to me who's in
2 charge of this model, and he has several people who
3 report to him.

4 Q Who are -- and just programmatically, who are the people
5 who report to the manager of strategy, are they people
6 from the program areas or distribution operation, where
7 do they come from, what does the team look like? I don't
8 need the names of the individuals, unless it's helpful.

9 A I guess I don't understand your question.

10 Q Is Ms. Hartwick a member of that team?

11 A No.

12 Q Who from -- are any of the other witnesses in this case,
13 like Mr. Deol, Ms. Elliott Andahazy, who support project
14 investments, are they members of that team?

15 A None of the witnesses who are in this case report to me
16 or to my manager.

17 Q Who, is it technical, who -- where in the Company org
18 charts, shall we say, does the GPM and the manager of
19 strategy sit, is it within regulatory affairs,
20 distribution operations? I'm just trying to get a sense
21 of what the nature of the people who make those decisions
22 are, nature of their job description.

23 A Well, I guess they report to me and I report to Bill
24 Chiu, who's the vice president, distribution operations,
25 I think engineering is the title. I'd have to check to

1 get the exact title for you.

2 Q So I'm trying to decide who decides whether to rank or
3 not rank a project in an iteration of the GPM?

4 A We put all of our strategic projects into the GPM. I
5 will need to check with my support team on what, why one
6 has a zero or 1. This is -- this is the GPM, these
7 projects are in it. Why they're on the right-hand list
8 and not the left-hand list is something I have to
9 confirm.

10 Q O.K. For purposes of top 50 list -- well, for
11 purposes -- scratch that.

12 Let's look back at the first set of, the
13 right-hand side -- I'm sorry -- the left-hand side of the
14 column or of the tab, column E, A12 tab.

15 A Can you repeat that?

16 Q I'm sorry. Column E --

17 A O.K.

18 Q -- it's labeled A12 tab.

19 A O.K.

20 Q Some of the projects and programs have a reference to
21 Schedule A-12, some say planned for IRM. Do you see
22 that?

23 A I do.

24 Q Can you explain the distinction, or --

25 A Yes. Generally I believe that tab would mean that if it

1 is, if it says, for instance, A-12 B5.4 Resilience,
2 that's the exhibit of the rate case that that investment
3 would be found in. If it says IRM, Planned for IRM, then
4 it would not be in an A-12 exhibit, it would be found in
5 a separate exhibit or in the IRM filing.

6 Q So if I, if I just want to look at the projects that are
7 planned for the IRM, there are, you can toggle it or I
8 can toggle it, but there's -- take my, you can check --
9 about 31 projects that are planned for IRM. Who decides
10 which projects will be rate case, which will be IRM?

11 A I'd say that is a collective decision between regulatory,
12 the PMO, my team.

13 Q What -- your team is -- I thought your team -- I'm sorry,
14 I misunderstood -- was the regulatory team. What's the
15 difference between your team and the regulatory team?

16 A My team handles capital planning, and DO regulatory
17 affairs, like the rate case. So the capital planning
18 portion of my team is responsible for the GPM.

19 Q O.K. So I think you said earlier that -- so I'm looking
20 at column G, the capital investments for programs where
21 it's a program as opposed to a project, these are a
22 five-year time period; is that right?

23 A That is typically how it is done, correct.

24 Q And if I scroll over to the project, and it's quite a
25 scroll, project list and spend, it's past all the orange

1 tabs?

2 A (Inaudible).

3 COURT REPORTER: I'm sorry. The what
4 tabs in the document, Mr. Kryscynski?

5 MS. ANDREWS: The project --
6 Mr. Kryscynski asked if we're moving tab now, I believe.

7 A I believe the word you were probably looking for was
8 Ms. Andrews said the word orange, as in the color.

9 Q (By Ms. Andrews): So for an attempt at clarity in the
10 record, I'm referencing the project list and spend tab in
11 the GPM model, which if I, subject to check or subject to
12 your confirmation, provides a project cost or a program
13 cost in column P.

14 A It says estimate in column P.

15 Q Yep. Would you agree that the estimate in column P on
16 project list and spend is carried through into the GPM
17 results capital investment column?

18 A I would have to check that. Would you like me to --

19 Q So. So why don't we look at pole and pole top
20 maintenance in both the GPM results, column G capital
21 investment, and project list and spend, column P
22 estimate.

23 A The project list and spend tab, row 17, column P, so P17,
24 the number I see is 1 -- I'm sorry -- 715,450,000, so 715
25 million 450 thousand.

1 Q And would you agree that's the capital investment for
2 PTMM shown in the GPM results column G?

3 A Checking. Yes, correct, that is the same number.

4 Q In that -- let me get it right -- project list and spend
5 tab, the estimate in column P is a hard number; do you
6 see that?

7 A Hard coded?

8 Q Hard coded, it's a real number, it's not a formula.

9 A That is correct.

10 Q Where does that number come from?

11 A That number will come from various places, depending on
12 the project or program.

13 Q Can you give me an example? Let's use PTMM, for example.

14 A PTMM, that project or that number will come from a, like
15 a collaborative effort between my team, engineering, and
16 the project management organization or the PMO.

17 Q And project management, what does the O stand for in PMO?

18 A Organization.

19 Q So is that like the organization that Ms. Elliott
20 Andahazy oversees or works in?

21 A She works in, yes.

22 Q So the row 7, distribution automation -- sorry, am I in
23 the right --

24 A Yes.

25 Q Who would have provided \$1.16 billion of program spending

1 for purposes of the GPM?

2 A It would have been a collaboration between engineering
3 estimates, project management, and then my team.

4 Q Which project management?

5 A I don't understand your question.

6 Q For distribution automation, what is the project
7 management organization responsible for distribution
8 automation?

9 A The project management organization is responsible for
10 distribution to automation construction. I don't
11 understand.

12 Q I'm sorry. Who within the PMO identifies the proposed
13 spending for a particular project?

14 A I think I explained that it is a collaboration between
15 engineering, the project management organization, and my
16 team.

17 Q What are the -- what are the -- how does that
18 collaboration determine, that group of people, that
19 collaborative effort, determine the estimate for the
20 project, for the program costs or the program estimate?
21 What are the factors that go into what the program
22 estimate is?

23 A Well, material costs, cost of construction, number of
24 circuits that need to be automated, availability,
25 projected availability of workforce in a given year, just

1 to name a few. There's numerous factors that we look at.

2 Q Do the estimated program costs change through the course
3 of the GPM as it -- you said it's run iteratively. Is
4 the estimate of the program cost -- the estimate of
5 investment, is that an estimate of investment over five
6 years?

7 A I'd say the estimate for all our programs and projects
8 can change as different factors change, it is definitely
9 possible for that to happen.

10 Q And what different factors would result in different
11 changes in program and project costs, categorically?

12 A As an example, material costs could go up or down.

13 Q The number of circuits to be cleared, hardened, treated
14 with PTMM would change, could change, and that would
15 affect the program costs over that period of time?

16 A If the Company had reason to do that, that could change,
17 that could affect it as well.

18 Q Does the Company reassess these program estimates
19 regularly, the team who's responsible for the GPM, is it
20 part of your maintenance of the model?

21 A Yes.

22 Q I'd like to look at the tab -- so orienting again back to
23 the tabs at the bottom of the model, after GPM results,
24 the blue -- sorry, the green tab, there's a series of ten
25 blue tabs; I didn't count them, but I'm assuming there's

1 ten considering they seem to correlate to each of the
2 impact dimensions, correct?

3 A Subject to check, correct.

4 Q All right. So generally speaking, the GPM results will
5 pull the score, will rank each project that is within
6 that sort of, subject to a particular impact dimension
7 within the impact dimension, and then the GPM results
8 will pull all of the results together; is that a fair
9 summary, and if not --

10 A Yeah. That was a bit of a confusing question, I
11 apologize. Could you restate it?

12 Q Yes. So could you tell me, sort of conceptually, the
13 model, how the GPM results reflect the results in the
14 tabs, the ten impact dimension tabs; what's the
15 relationship between the GPM results tab and each of the
16 impact dimension tabs, conceptually?

17 A So without offering an opinion on exactly how the model
18 functionally works, what I would expect to see would be
19 the scores from the different impact dimensions tabs
20 reflected in the GPM results. How that functionally
21 happens in the model, I would have to look.

22 Q O.K.

23 A And I will add, I cannot promise because I have not
24 checked, that it functions in the way that I believe it
25 to function conceptually, I would have to look at the

1 model specifically and trace the formulas.

2 Q O.K. That's fair. Let's look at that reduce electrical
3 hazards tab.

4 A Yes.

5 Q Again in this tab we have projects on the left and
6 projects on the right which have the same characteristics
7 as the GPM results tab, by which I mean the score for
8 ranking sometimes is -999, there's an on/off column T,
9 some projects are ranked, not all projects are ranked; is
10 that a fair summary of what we see in that reduce
11 electric hazards?

12 A I'm sorry, can you give me a minute, just I want to check
13 something in the model?

14 Q Yep.

15 A It might take me a minute here. I apologize. All right.
16 I'm sorry, I apologize for that. Will you please restate
17 your question?

18 Q Would you agree that the reduce electric hazards tab
19 follows the format of the GPM results tab such that there
20 is a set of ranked projects from column A to N, and then
21 there are what appear be a master set which includes both
22 ranked and unranked projects and programs starting in
23 column, in this case, P, generally?

24 A I agree that the programs that -- I agree that, yes,
25 there is a ranking, list of like ranked projects on the

1 left-hand side, and the right-hand side there is a
2 similar list to what is on the GPM results or what was in
3 the GPM results.

4 Q And the list on the right includes projects that are not
5 ranked, at least looking at column AQ where the score for
6 ranking is -999?

7 A I believe, subject to check, the score for ranking at 999
8 just means there is a zero score for this dimension,
9 although I'm looking now to see if that is indeed true.

10 Q It appears to be the case, but I didn't -- subject to
11 check?

12 A Subject to check.

13 Q So looking at the -- so would you agree that a project
14 that doesn't produce that is not a safety-driven project
15 or program would probably have a score of zero on the
16 reduce hazardous, reduce electric hazards tab?

17 A I would not characterize it that way, no.

18 Q How would you characterize?

19 A I would say that programs may be driven by other factors,
20 loading, reliability, but may also have a safety benefit,
21 and therefore would be scored with a safety benefit
22 included.

23 Q And the programs and projects that have a score of zero
24 in general reflect the facts that they are not driven by
25 their safety or reducing electric hazards but maybe score

1 high somewhere in one of the other impact dimensions?

2 A I think I would characterize it differently.

3 Q How would you characterize it?

4 A I would say a program or project with a score in this
5 dimension measures whether we're reducing electrical
6 hazards in the dimension in the ways that are measured,
7 which are basically wire downs and secondary cable
8 events. There are other safety issues or concerns that
9 we find on our system that are not scored in this tab,
10 but just because it does not have a safety score does not
11 mean that it's not a safety-driven project, it just may
12 not be, may not fit this definition that we find
13 (inaudible) --

14 COURT REPORTER: That we find -- I'm
15 sorry. That we find, last word?

16 A In the model.

17 COURT REPORTER: In the?

18 A In the model.

19 COURT REPORTER: O.K. Thank you.

20 A Model, GPM.

21 COURT REPORTER: Yes, thank you. You
22 just drifted off a little, sorry.

23 Q (By Ms. Andrews): So you said that there are two
24 components to a safety score, reduce electrical hazards
25 to the -- reduce electrical hazards impact dimension,

1 wire down safety, and reducing secondary cable events.

2 Do I have that right?

3 A That is my understanding, correct.

4 Q And so we see in row 8 wire down safety in columns F, G,
5 and H, and cable network primary/Pontiac Vaults in I, J,
6 K, right?

7 A Correct.

8 Q What is Pontiac Vaults?

9 A So I can give you a quick overview, although I am not the
10 expert in this particular project, and I also believe
11 this project is largely complete, but it was a special,
12 specialized system in the city of Pontiac that was built
13 underground and had some very, very specific safety
14 concerns with how the equipment was constructed and how
15 operations needed to happen in these underground vaults.

16 Q Did the Company -- what was the remedy -- what was --

17 A There was a project which I, again, I believe is largely
18 complete, subject to check, or it's, if it's not -- I
19 believe it's largely complete, subject to check, I could
20 be, again, wrong -- where what we did is we replaced the
21 equipment in that, in those vaults. Again, at this
22 point, I think my technical knowledge of this project
23 needs to be deferred, I do not have anything past that.

24 Q Do you know if the Pontiac Vaults project scored well in
25 the Pontiac Vaults safety dimension?

1 A I would have to look.

2 Q Wire down safety, there's a wire down reduction, you see
3 it in column F; are you with me?

4 A Are we looking for Pontiac Vaults or are we --

5 Q No. I'm just, generally, I'm understanding what the --

6 A Yep, that's correct.

7 Q Looking at distribution automation wire down reduction,
8 7,686, where does that number come from, who provides it?

9 A That would likely be a combination of our engineering
10 team and, our engineering team, our data scientists who
11 monitor and maintain wire down records, and then my team
12 kind of pulling together what we believe based on what
13 our engineers are telling us, what we believe the wire
14 down reduction will be; and for distribution automation,
15 it's particularly focused on eliminating live wire downs,
16 energized wire downs.

17 Q How can -- is that a number of wire downs that will be
18 reduced over the project period, is that a -- where did
19 that -- where in the model does that number come from?
20 It's coded and I -- which tab would that be drawing from,
21 how can we validate that?

22 A Give me a second here. I do, I see a formula in F13, I
23 don't see it hard coded, but it would be farther back in
24 the model.

25 Q Right. How is that checked to ascertain its, its
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1 reasonableness?

2 A How is it checked?

3 Q Yeah.

4 A I guess I don't feel like we -- we run the calculation
5 ourselves, so we check it ourselves when we do the
6 calculation. I don't understand your question.

7 Q Do you validate that based on distribution automation
8 projects that have been previously installed?

9 A We look at all of our, all of our data, particularly for
10 the programs, and check them for how they're performing.
11 Distribution automation is a new program, and so we still
12 have the data that's coming in, but it will be checked as
13 it comes through.

14 Q How does the wire reduction of 7,686 translate into a
15 wire reduction score of 1.9 million?

16 A All right. Let's see. Let me walk through the
17 calculation. Give me second, might take me a minute.

18 (Brief pause.)

19 A All right. Can you restate your question so I can make
20 sure I get it answered correctly?

21 MS. ANDREWS: I'm afraid I have forgotten
22 my question. Could I get help here --

23 COURT REPORTER: Yes.

24 MS. ANDREWS: -- Lori, please.

25 (The record was read aloud as follows:

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1 "Q How does the wire reduction of 7,686 translate
2 into a wire reduction score of 1.9 million?"

3 A Sure. If you look at the 1.9 million, what you can see
4 is formula Y23 times Z\$6 times Z\$7, and then when you
5 look at each of those components, you look at Y23, Y23,
6 the formula is $X=X23$ divided by $Z5$. So what this is
7 doing, what Y is is the percentage of total wire downs on
8 the system that this program is expected to produce, and
9 so, you know, live wire downs, my understanding, subject
10 to check. And so what we're saying is this distribution
11 automation program has the potential to reduce 66% of our
12 live wire downs, and if you -- and so, as I said, it's
13 $X23$, which is the 7,686.1, divided by $Z5$, which is
14 11,643, and so that's how we get the percentage 66. From
15 there, using subject matter expert guidance, we use
16 weighting factors of relative size of 1 million and a
17 relative probability of 3, that's $Z6$ and $Z7$, to multiply
18 and get a score of 1,980,443. Does that answer your
19 question?

20 Q (By Ms. Andrews): Yes. So when you said live wires,
21 does the Company track live versus, wire downs that are
22 live versus wire downs that are not live?

23 A I would, my guess is that -- I would have to check on
24 that, I do not know the exact percentage.

25 Q O.K. So it's whatever the Company tracks in terms of
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1 wire downs, whether it's live or not live?

2 A Yes, subject to check.

3 Q And when you said of the wires down, wire downs on the
4 system, the 11,643 shown in column Z, row 5, that is of
5 the projects that are being, that are being tallied,
6 correct, not the system wide?

7 A I would have to check that, I do not know off the top of
8 my head.

9 Q It's a hard number, so I'm not sure where it comes from.

10 A Yep, I understand. I would have to check, I do not know
11 off the top of my head.

12 Q O.K. And the 66% -- sorry. So then you said a relative
13 probability of 3. Relative probability of what?

14 A Relative probability of 3.

15 Q But a probability of what happening or not happening?

16 A I think relative probability of a wire down occurring
17 compared to, compared to I think relative probability of
18 the other factor we're looking at, but I would have to
19 check that to be sure, check with my SMEs. That's my
20 understanding.

21 Q O.K. And the relative size, 1 million versus 4 million,
22 did that come from an SME as well?

23 A That is my understanding.

24 Q O.K. And so then the total score after calculating wires
25 down and the percent of the total and the relative

1 probability and the relative size ends up with a wires
2 down score, correct? That's what you just helped me
3 understand?

4 A Well, I -- yeah. I'm sorry, will you state that question
5 again?

6 Q I think you said you multiply the wires down reduction by
7 the, as a percentage of the total, and then you take
8 that, multiply it by the relative size and relative
9 probability to end up with a final score?

10 A That is what the formula does, correct.

11 Q O.K. So you do that for every wire down safety project
12 and for every cable or Pontiac Vaults project, right?

13 A That is correct.

14 Q And then you add them together, that's in column L?

15 A Column L?

16 Q Sorry. Wire down secondary cable --

17 A No, they're not added together in column L.

18 Q What is column L showing?

19 A Well, column L is a V lookup formula.

20 COURT REPORTER: Excuse me. Is a what
21 formula?

22 A V lookup. V as in volume, V lookup formula.

23 COURT REPORTER: Thank you.

24 Q (By Ms. Andrews): So unless I'm missing it, it looks to
25 me like column L equals either the wire down score or the

1 cable score or the wire down plus the cable score where
2 there are scores in both?

3 A It is my understanding, subject to check, that the
4 addition of the scores happens in the right-hand table,
5 not in column L, and that column L looks up into the
6 other table.

7 Q I see. Thank you. The practical effect appears to be
8 the same, subject to check?

9 A Subject to check.

10 Q Thank you. The safety per incident -- per million
11 dollars invested is a measure, we talked about this
12 earlier in your testimony, it's a measure of the score,
13 the safety score divided by the project cost, so how many
14 scores, how many wire downs, how many wire down or
15 secondary cable safety points relative to the program
16 cost?

17 A Sorry, that was a bit of a long question, can you try it
18 again for me?

19 Q Yep. Why don't you tell me the math to get from the wire
20 down safe, secure cable score to the safety per dollar,
21 million dollars invested?

22 A O.K. Give me one second, please. O.K. So you are --
23 just to be safe and to be clear, will you please restate
24 your question? I believe I can answer it now.

25 Q Can you explain how the safety per million dollars

1 invested correlates to the wire down secure cable
2 combined score?

3 A How it -- sure. So in column AH, we add the wire down
4 score with the, what I'll call for shorthand the
5 secondary cable score. In this case, you know, for
6 distribution automation, I'm looking at row 22, there is
7 no secondary cable score, so it is just the wire down
8 score, 1,908,443. We then take that score and we, if you
9 look at column AI, we take, again, we take that score in
10 AH23 and we divide it by W23, which is the project cost
11 divided by a million just for scaling purposes, and so we
12 take that, and once you do that math, it comes out with,
13 comes up to 1,703. Is that your question?

14 Q Yes. Thank you.

15 A O.K.

16 Q 1,703 is not the dollars, right, that's the wire down
17 reduction in this case, wire down safety improvement per
18 dollar spent -- per million dollars spent?

19 A That's correct. It's wire down, the wire down score, the
20 score we have given the project's ability to eliminate
21 wire downs divided by the cost of the project, or in this
22 case, the program over a five-year period.

23 Q The next column then translates the wire down per million
24 dollars spent score into a score?

25 A Correct.

1 Q How?

2 A So this is where we index the score, and I think maybe
3 it's best if I read from my testimony because I think
4 it's explained well there. So if you just give me
5 second, I'll pull that up. Found it, give me one second.
6 O.K. So here's what's in my testimony, I'm on page 82 of
7 my direct testimony -- I'm sorry -- 62.

8 Q Thank you. I thought I was on the wrong page.

9 A 62 of my direct testimony, line 1. And I will -- I'll
10 read, and that says -- and I say: Each program's
11 benefit-cost score for each impact dimension is indexed
12 so that a project with a benefit-cost ratio at the 95th
13 percentile receives a score of 100. Projects scoring
14 exceptionally high, above the 95th percentile, will
15 receive a score above 100. This method provides three
16 benefits.

17 Q O.K. Let's stop right there. The benefits we can refer
18 to the testimony for. What I'm trying to understand is
19 how do we go from 95th percentile will receive a score of
20 100, but this project, distribution automation, received
21 a score of 286?

22 A Sure, I can explain that. So if look at the formula in
23 column AJ, formula is, (AI23 divided by AJ \$6) times 100
24 times AJ \$7. So in essence what's happening here is if
25 you look at the AI23 divided by AJ \$6 part of the

1 formula, what you can see is the normalization factor,
2 and that's the indexing. So the 1,786 is equivalent to
3 the 95th percentile that I talked about in my testimony.
4 And so what this part is doing is it's taking the 1,703,
5 dividing by the 1,784, and then multiplying that by 100,
6 so that gives you your index score. And what this model
7 is doing is then, without having an extra step, another
8 column, it's also adding the weighting at the same time,
9 which is 3 for this dimension. And so we have, what we
10 get to is 286.3. If you wanted to just see the raw index
11 value, you'd divide this score by 3.

12 Q O.K. If you divide it by 3, that would give you a --

13 O.K. That would give you a score under 100, right?

14 A That is correct.

15 Q O.K. I am going to take --

16 MS. ANDREWS: I think we need -- I need a
17 break, and I think it's time for our break, and -- or I'm
18 happy to keep going, but I'm going to slightly switch
19 gears.

20 JUDGE WALLACE: O.K. Why don't we --
21 O.K. Do we want to break for lunch now, and that would
22 give Mr. Kryscynski an opportunity to look up some of the
23 things that you had asked about earlier, or do we want to
24 take a ten-minute break and then break maybe at 12:30;
25 what works best for people?

1 MS. ANDREWS: I defer to the witness.

2 MS. HAYDEN: Could we take a 15-minute
3 break, your Honor, and continue on, would that be O.K.?

4 JUDGE WALLACE: Sure. Off the record.
5 Fifteen-minute break. See you at quarter till 12:00.

6 (Recess from 11:28 a.m. until 11:49 a.m.)

7 JUDGE WALLACE: All right. Back on the
8 record. Please continue, Ms. Andrews.

9 Q (By Ms. Andrews): So Mr. Kryscynski, looking at the GPM
10 results tab of the GPM model, the green tab again,
11 looking at the regulatory compliance column, which is
12 column K; do you see that, are you with me?

13 A I will be shortly. Yes.

14 Q It appears that two projects or two programs scored in
15 the regulatory compliance impact dimension, correct?

16 A That is correct.

17 Q And that's the frequent outage program, CEMI, and the
18 PTMM program?

19 A Yes, CEMI, the CEMI program, frequent outage program, and
20 the PTMM program, correct.

21 Q Thank you. I always mispronounced it as CEMI. Thank
22 you. So the regulatory compliance has a weighting of 2,
23 correct?

24 A That is correct.

25 Q All right. So let's go to the regulatory compliance tab

1 in the model.

2 A Yep.

3 Q So in the right-hand -- I mean the left-hand side of the
4 column where the projects are ranked, we only see the
5 CEMI program ranked; do you see that?

6 A I do see that, yes.

7 Q But if we look over on the left-hand side of the column,
8 we see the pole top and, the PTMM program, it's in row
9 20, also receiving a score of 100 weighted to 200; do you
10 see that?

11 A Yes, correct.

12 Q Why -- selected in column O appears to either yes, you
13 know, rank or not rank a program; is that right?

14 A Give me one second, please. Column O has a formula in it
15 that looks back at a different, different tab.

16 Q Back at the project and list -- project list and spend
17 tab?

18 A That's correct.

19 Q So the project list and spend tab does include the PTMM
20 program. What in particular is selected or not selected,
21 like why does PTMM not show a rank; what does the project
22 list and spend tab tell us?

23 MS. HAYDEN: I'm going to object to the
24 form of the question. I think there were two or three
25 questions in there. Maybe we could break it down.

1 Q (By Ms. Andrews): How does the project list and spend
2 referenced in the regulatory compliance column O relate,
3 how do they relate to each other?

4 A Let me just take a second and trace it back to the model.
5 One second.

6 Q Yep. Can I help you?

7 A I'm almost there, just give me one second. All right.
8 So why don't, again, just for clarity and make sure we're
9 on the same page, if you'd re-ask your question, I think
10 I hopefully can answer it.

11 Q What in the project list and spend tab prevents PTMM from
12 being ranked in the regulatory compliance tab?

13 A So if you look at the project list and spend tab, you
14 have a table from columns A through, it's A through N, it
15 goes farther, but A through N primarily is what I'm going
16 to talk about for the answer here, and in, it has the ten
17 dimensions, E through N, and in those ten dimensions,
18 each project is, has an X in it if it has a score in one
19 of those dimensions. This is my understanding anyway
20 from my brief review of the model on the stand here. And
21 so anyway, it gets a score. So in this particular case,
22 PTMM does not have an X, which appears to be an error in
23 terms of it should. Now, while it does not have a score
24 in the regulatory -- while it doesn't get ranked on the
25 regulatory table in regulatory compliance tab columns B

1 through G, even though it should and does have a score,
2 it does, unless I'm mistaken, get pulled in correctly to
3 the actual GPM results.

4 Q So the GPM result is not pulling from the ranked rows,
5 it's pulling from the unranked rows on the left -- on the
6 right I mean, from the regulatory compliance?

7 A So I could spend a lot of time going through the model to
8 answer your question very specifically. My suspicion,
9 given what we're seeing, is the GPM results tab is
10 pulling the raw scores -- or I don't want to say raw
11 scores -- but the scores from the individual tables
12 directly, and that when you look at the specific, like
13 the overload -- no, sorry -- regulatory compliance tab,
14 right, this table on the left is kind of a separate
15 subset table for ease of use for looking at each
16 particular tab, and in this particular case, yes, it
17 should have had PTMM in this table, but did not affect
18 the overall score.

19 Q Is it fair to say that regulatory compliance component of
20 PTMM relates to the inspection requirement, the
21 Commission's requirement to inspect poles and pole tops?

22 A I believe I answered a discovery question on this; if you
23 give me second, I will find it. Might take me a minute,
24 there's a fair amount of discovery here. I believe I'm
25 on the correct discovery question. Will you restate your

1 question now?

2 Q For the PTMM program, the regulatory compliance score,
3 does that relate to the Commission, the obligation to
4 inspect poles and pole tops?

5 A So in my Discovery MNSCDE-15.4a-b, I believe your MNSC,
6 you guys asked the question related to why we ranked this
7 in regulatory compliance, and we provided the MPSC
8 Staff's Utility Pole Inspection Program Investigation
9 Staff Report from 2009 where it says Staff recommends
10 that both companies achieve an 8- to 12-year pole
11 inspection cycle frequency to correlate with the standard
12 recommended by the USDA Rural Utility Service for
13 Michigan's (inaudible) Zone.

14 COURT REPORTER: Utility Service what
15 zone?

16 A Decay Zone, D-e-c-a-y.

17 Q (By Ms. Andrews): So the answer is it goes to the pole
18 inspection requirements in the Commission rules?

19 MS. HAYDEN: Objection. I don't believe
20 that's what the witness stated.

21 Q (By Ms. Andrews): Can you cite -- I'm sorry. Can you
22 cite the program, the -- can you read your response
23 again, please? I was trying to take notes as you were
24 reading it.

25 A Absolutely. So the answer reads -- again, this is
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1 MNSCDE-15.4a-b. Please see the MPSC Staff's Utility
2 Inspection Program Investigation Staff Report,
3 (11-20-2009). 4. Staff recommends that both companies
4 achieve a 10-to 12-year pole inspection cycle frequency
5 to correlate with the standard recommended by the USDA
6 Rural Utility Service for Michigan's Decay Zone.

7 Q Thank you.

8 A Absolutely.

9 Q Can you look at the reliability -- I'm sorry -- the
10 reliability SAIDI tab.

11 A Sure.

12 Q The SAIDI CMI before for programs, there is not a CMI
13 before, that's only for projects; is that correct?

14 A Please restate that question, I didn't catch it.

15 Q The reliability SAIDI tab does not reflect a CMI before
16 for programs, only for projects, correct?

17 A Typically that is true, subject to check, yes.

18 Q So it's not taking a baseline reduction, it's taking a
19 programmatic reduction over a period of time for
20 programs?

21 A For all programs, we are calculated -- calculating the
22 CMI minutes avoided for both programs and projects.

23 Q O.K. So for CMI savings, that means CMI minutes avoided?

24 A CMI minutes avoided, correct.

25 Q So for the pole and pole top maintenance program, the CMI

1 savings or the CMI minutes avoided is a cross-reference
2 to another tab, to the input data tab; would you agree?

3 A I don't know what cell you're looking at.

4 Q I'm sorry. I'm looking at column W, row 22, the pole and
5 pole top maintenance on the right side of the tab.

6 A It does appear to be referencing if you look up into the
7 data input tab, correct.

8 Q And in the input data tab, if we scroll over to that
9 column BK, row 30, you see the same 200 --

10 A Sorry.

11 Q Yep, yep.

12 A Can you --

13 Q Yep.

14 A O.K. I'm on that tab. What -- where would you like me
15 to look?

16 Q Row, sorry. Row 30, column BK. BK is labeled system
17 minutes interrupted, I believe, sMinInt; is that your
18 understanding?

19 A S minutes interrupted, which I assume S would be for
20 system, pending the check.

21 Q Subject to check?

22 A Subject to check.

23 Q So you, so the, the reliability SAIDI tab references the
24 input data tab. Would you agree that the input data tab
25 in turn references the program project benefits tab?

1 A I would agree with that, yes.

2 Q So that's the next tab over to the right?

3 A Correct.

4 Q And row 15, column H, you see the avoided minute
5 interruptions CMI for poles/PTM?

6 A Correct.

7 Q And you agree that number is hard entered?

8 A Correct.

9 Q That information, where did that information come from?

10 A Came from a combination of my team, our engineering team,
11 and our data analytics team.

12 Q Do you know if the avoided minute interruptions is over
13 the same period as the program spending period, the five
14 years?

15 A That is my expectation and my understanding.

16 Q Does the Company -- just a second. Would you agree that
17 on the PTMM program, the Company has prioritized
18 different circuits based on the benefits that would be
19 achieved, the relative improvements that may be achieved
20 based on particular conditions on circuits?

21 A I'm sorry, one more time on that question, please.

22 Q Does the Company prioritize which circuits it will treat
23 with pole top maintenance and modernization?

24 A Do we prioritize which circuits we do?

25 Q Yes.

1 A Yes, there is a selection process that occurs between my
2 team and the PMO team and in consultation with our field
3 engineers on which circuits are chosen annually.

4 Q Would you agree that in general the Company would select
5 circuits where the benefits are higher sooner, elect to
6 treat circuits where the benefits are higher first and
7 not circuits where the benefits would be lower first?
8 Would it prioritize treating worse performing circuits
9 over better performing circuits?

10 A I believe Witness Elliott Andahazy covers PTMM and the
11 prioritization circuits extensively in her testimony, and
12 I would defer any questions on the specific
13 prioritization of PTMM to her and how that (inaudible) --

14 COURT REPORTER: And how that?

15 A -- and how they are prioritizing their individual
16 circuits.

17 COURT REPORTER: Thank you.

18 A Apologize for speaking too fast.

19 Q (By Ms. Andrews): Would you agree that the GPM does not
20 differentiate between a dollar spent in 2024 or a dollar,
21 or a million dollars spent in 2024 versus, say, 2026 in
22 terms of the benefits it would receive, the CMI avoidance
23 per million dollars invested?

24 A I would -- I would say that the dollars, dollars put in
25 for the program are the expected dollars that we will

1 spend over a five-year period, and the benefits received
2 are those benefits over a five-year period.

3 Q O.K. It does not attempt to correlate the spend to the
4 prioritization within the program?

5 A It looks at the spend and the benefits at a program level
6 over the five years.

7 Q So the GPM doesn't assess which circuits within a
8 program, it only assesses PTMM versus another program,
9 ranking PTMM versus another program or project?

10 A I wouldn't characterize it that way.

11 Q How would you characterize it?

12 A I would say, subject to check, my understanding when
13 we're looking at the PTMM program, we are looking at our
14 list of -- when we're looking at benefits, we're looking
15 at the list of circuits we expect to be investing in over
16 the next five years.

17 Q O.K. That group or that five-year program versus another
18 program in the, or project in, that's ranked in the GPM,
19 it's not looking at within the program?

20 A I think we kind of got interrupted in the middle of that
21 question, maybe by me. Could you restate the -- I'm not
22 fully getting the question you're asking or understanding
23 it, so can we just back up for a second?

24 Q The GPM is not attempting to prioritize within a program,
25 only program to program and project level, correct?

1 A GPM is not responsible for prioritizing within a program,
2 that is correct.

3 MS. ANDREWS: I'm going to switch gears
4 at this point, and I can lay some -- oh, you know what,
5 at this point I would actually like to offer the working,
6 workpaper version of the GPM into the record as an
7 exhibit. The Exhibit A-43 Schedule HH4 doesn't have the
8 formulas intact, and all of our record has been using the
9 workpaper version.

10 JUDGE WALLACE: Do you have an exhibit
11 number for that?

12 MS. ANDREWS: I don't have an exhibit
13 number. I can, I can create one.

14 UNIDENTIFIED: 28.

15 MS. ANDREWS: 28? It can't be 28.
16 Sorry, my colleague just -- can we go off the record for
17 just a second?

18 JUDGE WALLACE: Off the record.

19 (Brief off-record discussion at 12:14 p.m.)

20 JUDGE WALLACE: Back on the record.

21 MS. ANDREWS: Your Honor, at this point I
22 would move for the admission of Exhibit MEC-71, which is
23 the workpaper we've been discussing with the label WP AJK
24 U-21534 GPM.xlsx.

25 JUDGE WALLACE: Is there any objection to
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1 the admission of Exhibit MEC-71?

2 MS. HAYDEN: No objection.

3 JUDGE WALLACE: Hearing none, the exhibit
4 is admitted.

5 MS. ANDREWS: Your Honor, before we move
6 on -- thank you, your Honor.

7 Q (By Ms. Andrews): Mr. Kryscynski, if you could look in
8 the folder at what's been labeled MEC-37.

9 A Let me do that, MEC-37, I see it, I'm opening it. Make
10 it bigger because it's very small. Got it.

11 Q Yeah. Do you recognize this as an exhibit from 21297
12 sponsored by you with the scores for the GPM ranking in
13 the last rate case?

14 A I have not reviewed this since the last rate case, but
15 subject to check, yes.

16 MS. ANDREWS: Your Honor, at this point I
17 would move for the admission of Exhibits MEC-36 and
18 MEC-37.

19 JUDGE WALLACE: Is there any objection to
20 the admission of Exhibits MEC-36 or MEC-37?

21 Hearing none, those exhibits are
22 admitted.

23 MS. ANDREWS: I can keep, move on to the
24 next topic.

25 JUDGE WALLACE: I'm thinking maybe we

1 should, just since you're at a point where you're moving
2 to a different area, we can go ahead and break for 45
3 minutes to an hour for lunch now. Would that be O.K.?

4 MS. ANDREWS: Fine with me. Is that O.K.
5 with the witness?

6 THE WITNESS: I have no objection.

7 JUDGE WALLACE: O.K. How long, are you
8 guys O.K. with 45 minutes, or is an hour better?

9 MS. HAYDEN: Forty-five.

10 MS. ANDREWS: Forty-five minutes would be
11 good, just so we can get through today's schedule.

12 JUDGE WALLACE: Perfect. O.K. It's,
13 let's say it's 12:15, I'll see you all back here at 1:00
14 o'clock. Off the record.

15 (At 12:19 p.m., the hearing recessed for lunch.)

16 - - -

1 Thursday, September 5, 2024

2 At 1:04 p.m.

3 - - -

4 (Hearing resumes following the lunch recess.)

5 JUDGE WALLACE: All right. Back on the
6 record in Case No. U-21534, Ms. Andrews, please go ahead.

7 MS. ANDREWS: Thank you.

8 - - -

9 A L L E N J. K R Y S C Y N S K I, J R.
10 resumed the stand, and having been previously sworn,
11 testified further as follows:

12 CROSS-EXAMINATION (Continuing)

13 BY MS. ANDREWS:

14 Q Mr. Kryscynski, starting on page 69 of your direct
15 testimony, you support the Company's reliability model;
16 is that right?

17 A That is the correct.

18 Q You describe functionally or methodologically how the
19 model works through about the middle of page 74 of your
20 direct testimony, right?

21 A I talk about the reliability model through page 74 of my
22 direct testimony.

23 Q And one of the outputs of the reliability model is a
24 projection of all-weather SAIDI in 2024 and 2025 versus
25 historic baseline all-weather SAIDI, right?

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1 A That is correct.

2 Q The Company, the testimony on page 69 also includes a
3 projection of the SAIFI benefits in 2024 and 2025,
4 correct?

5 A What page did you say, page 70?

6 Q 69.

7 A Yes, 69, correct.

8 Q And all-weather SAIDI, would you agree, is generally a
9 measure of the customer total system experience in terms
10 of reliability, good days, bad days, blue skies and
11 storms, total all customers, all minutes over the course
12 of the year?

13 A The way -- so we can make sure we're on the same page,
14 the way SAIDI is calculated is all minutes of customer
15 interruption divided by the total number of customers; so
16 in essence it's the average amount of time an average
17 customer will be out in a given year.

18 Q Who -- why did DTE develop the reliability model?

19 A It developed the reliability model prior to the 2023 DGP,
20 so I would say, let's say primarily developed in 2023
21 between January and September for a very rough time
22 period.

23 Q And was your team responsible for the development of the
24 reliability model, or who was responsible for it?

25 A It was a combination of my team and our data science

1 team, with consultation and inputs from a variety of
2 subject matter experts across the Company, including
3 engineering and I believe PMO as well.

4 Q O.K. So just in general, your testimony on page 70, your
5 direct testimony outlines the five steps that the model,
6 the process that the model takes from a baseline to
7 calculate that all-weather performance that we just
8 referenced, the SAIDI scores for 2024 and 2025; is that
9 right?

10 A That's correct.

11 Q All right. So first we start with a baseline,
12 circuit-level baseline of reliability performance over a
13 five-year period; is that right?

14 A That is correct.

15 Q The baseline, so then you estimate the impact of each
16 reliability program that's being assessed, correct?

17 A Apologize, could you restate that question for me?

18 Q You estimate the impact of the reliability programs that
19 are being, that are included in the model?

20 A We estimate the impact or the event reduction that we
21 would see from each of the programs.

22 Q Going forward, right?

23 A Going forward, correct. Well, and we also look at, we
24 also account for programs that have occurred in the past
25 as well, so as an example, tree trimming, we look at not

1 only future trim but trim that has occurred in the past.

2 Q And the trim that happened in the past is captured in the
3 baseline? Let me rephrase. You know what, let's hold
4 off on exactly how past programs are incorporated in
5 because we're going to look at the model in a second and
6 I think it will be pretty clear how that works. But just
7 conceptually, the programs that are included are sort of
8 applied to the outage, baseline outage events.

9 The Company also estimates the impact of
10 system degradation, so this is sort of the absence of the
11 reliability programs; is that fair?

12 A That's fair.

13 Q Then the Company has an investment plan, which is sort of
14 the planned tree trim or capital program for each
15 circuit, so, for example, a tree trim in 2023 will be
16 reflected in the investment plan for a particular
17 circuit?

18 A Correct.

19 Q Then DTE calculates the performance based on the
20 baseline, assuming the benefits for each program for the
21 performance of that circuit for each year in the study
22 period, right?

23 A One more time. Apologize.

24 Q DTE -- I'm looking at line 14 on page 70, calculate
25 ex-MED performance, so the combined, you combined the

1 baseline performance with the investment plan on a
2 circuit level to project future performance?

3 A Correct.

4 Q And then DTE calculates that, scales that ex-MED output
5 to an all-weather output, right?

6 A Correct.

7 Q All right. So let's look at the model, Exhibit A-43
8 Schedule HH, I have 4, but I think it might be 5. I'm,
9 in my notes, it's HH5. Sorry, my notes are incorrect.
10 Schedule HH5 is the reliability model. There's a, there
11 are two versions of it in the SharePoint, one is the
12 exhibit version and one is the workpaper version of the
13 reliability model?

14 A All right.

15 Q Are you with me?

16 A I am.

17 Q O.K. You can open whichever one you like.

18 A All right. O.K.

19 Q I recommend the workpaper version, but --

20 A That is the version I have open.

21 Q O.K. So the first tab in the model is program inputs.

22 Are you with me?

23 A Yes.

24 Q All right. And basically these are the, this tab shows
25 the six programs that are included in the reliability --

1 the five programs that are included in the reliability
2 model, which are tree trimming, hardening, PTMM,
3 conversion, and automation, correct?

4 A Correct.

5 Q And just conceptually, the units by year, all of the
6 units for all of the programs except automation are
7 miles, circuit miles, correct?

8 A That is correct, yes.

9 Q And then the units for automation is the reclosers?

10 A I believe so, yes, that's correct.

11 Q The next tab -- and this generally reflects the units by
12 year, the Company's proposed investment plan as shown in
13 the DGP, maybe with some tweaks based on modifications to
14 the DGP, but in general, it aligns with the DGP?

15 A I would say that these investments align with our most
16 recent thinking at the time we filed our rate case.

17 Q O.K. So let's look at the next tab, the circuit info and
18 calculations.

19 A O.K.

20 Q Just for context, this tab provides information on I
21 think it's 3,295 circuits, subject to check?

22 A Would you like me to check?

23 Q I mean does that sound in the scale of accurate?

24 A It sounds like it is in the scale of accurate.

25 Q For each circuit, the Company provides the voltage,

1 whether it's 4.8, 13.2, or something else, whether it's
2 active, and then also the number of customers and miles
3 overhead and underground per circuit, correct?

4 A That is correct.

5 Q O.K. So then we get into -- then the model, the circuit
6 info tab breaks, provides the baseline; would you agree
7 with me? Starting at column L through BA is the raw data
8 for the baseline calculation of circuit-level baseline
9 reliability performance; is that right?

10 A L through what? Column L through what did you say?

11 Q BA. Do I have --

12 A I think, yes, L through BA provides various views of the
13 circuit-level event reliability data.

14 Q All right. And again, this is broken down for each year,
15 2017 through 2022, and we can start -- it's broken into
16 outage events and non-outage events, right?

17 A It is broken down into --

18 Q At the highest level of --

19 A Sorry, I just have to scroll up. Yes.

20 Q Yep.

21 A At the highest level, which is row 3 in this case, outage
22 events and non-outage events.

23 Q All right. So we're going to focus on outage events.

24 Would you agree generally that the reliability model
25 mostly focuses on outage events, not non-outage events?

1 A For the reliability projections, correct, yes.

2 Q And within, so within the outage events -- and these are
3 all non-MED outages, correct?

4 A That is correct.

5 Q Within the outage events, non-MED outage events, the
6 model breaks down the data into tree and non-tree outage
7 events, right?

8 A Is that a question or a statement?

9 Q That was a question, just confirming for the record.

10 A Yes, the model breaks down between non-tree and tree
11 outage events.

12 Q And then within each non-tree and tree, there's multiple
13 and single, and I'll make a compound question; single
14 just means one customer experience that non-tree not MED,
15 whereas multiple means multiple customers experience that
16 non-tree non-MED outage event, correct?

17 A Let me -- I believe that is correct, but let me restate
18 it the way I would put it, which is for -- difference
19 between multiple and single events are multiple would be
20 one event causes multiple customer interruptions, so more
21 than one, and a single event causes one customer
22 interruption, be it tree or non-tree, that's how I would
23 define the difference between multiple and single event.

24 Q So multiple and single refers to customers, not events?

25 A Yes, the amount of customers affected by a single event.

1 Q All right. And so when we -- would you agree with me,
2 just for simplicity and without minimizing the analysis
3 in the model, we're mostly focusing on the multiple tree
4 and non-tree outage events, correct? The singles are a
5 much, much smaller subset in the reliability model's
6 impacts?

7 A If we are defining impacts as impact on SAIDI and SAIFI,
8 I would agree that the multiple events are the largest
9 driver of those metrics.

10 Q So I'd like to understand the difference between tree and
11 non-tree. Can you tell me what is the difference between
12 a tree and a non-tree outage event?

13 A Yes. A non-tree outage -- well, let me start it the
14 other way. A tree outage event is an event that we have,
15 we have cause coded tree, tree, tree wind, and a
16 non-outage event is an event that we don't believe was
17 caused by a tree.

18 Q So if you can turn to your rebuttal testimony on page 16.
19 Sorry to make you flip around.

20 A No problem at all. I have this big binder here for a
21 reason. Page 16 you said?

22 Q Page 16.

23 A Yep.

24 Q There's Figure 1, customer interruptions by cause code;
25 do you see that?

1 A Yes.

2 Q That was the subject of a conversation we had yesterday,
3 you might have been watching. The cause codes are listed
4 along the bottom of the axis: Equipment, non-tree, wind,
5 unknown, et cetera; do you see that?

6 A I do.

7 Q Which of the cause codes are non-tree?

8 A Non-tree would be equipment, subject to check, my
9 understanding is it would be equipment, unknown,
10 intentional, animal, other, public interference, weather,
11 loading, customer.

12 Q So anything that's not tree or wind is non-tree?

13 A Correct.

14 Q O.K. And then I'd like to look at, in the folder, in the
15 SharePoint folder, there is a, there's a discovery
16 response, there's an Excel that's U-21534 MNSC-3.1-01,
17 it's an Excel file 3.1-01 Outages 2017 through 2023.

18 A Pulling that up. Actually, it might be easier if I
19 download this first. All right. I have it open.

20 Q Is it your understanding that the outage cause codes in
21 your rebuttal testimony generally correspond to the
22 primary cause category in the Outages 2017 to 2023 Excel?

23 A Generally correspond to the -- do you have a column? Is
24 that H?

25 Q Yep.

1 A I would have to check. I believe we provided the
2 analysis in discovery for this chart, so that's what I
3 would refer to you -- refer you to.

4 Q O.K. Just a second. So if you look at what's labeled
5 Exhibit MEC-35 in that SharePoint folder.

6 A Looking for it. Yes, 35. Opening it.

7 Q I appreciate that this is a response from Ms. Steudle,
8 but it indicates that tree-caused outages are typically
9 coded, and then it identifies how they're coded, and then
10 it says: Outage data by cause code has been provided in
11 discovery response. Is that your understanding of the
12 source of the data for tree-caused outages and non-tree-
13 caused outages, non-tree outages?

14 A I think that's an excellent question for Witness Steudle
15 who's provided this response. I can respond to the
16 analysis I provided and the Excel data analysis that I
17 provided with it in discovery.

18 Q Do you have a discovery response that you're referring
19 to?

20 A I can look it up. Apologize, taking a minute to find it.

21 Q I'm not sure I know what you're referring to, but to the
22 extent it helps, I'm looking for what I think you might
23 be referring to, and I haven't found it yet.

24 A Hopefully I'm not misremembering something, there's been
25 a lot of discovery, so it is possible I made an error.

1 But if you give me a second, I'll take a look. Do you
2 remember what page that figure was on that you're
3 referring to? I think I found it. Figure 1. So if you
4 look at MNSCDE-18.8b, it says: Produce the data
5 supporting Figure 1, right, regarding to my rebuttal
6 testimony here, and it says: Answer: Please see the
7 attached document, and the attachment is U-21534
8 MNSC-18.8b, Figure 1.

9 Q O.K. Sorry. So I'm sorry, I might -- I'm -- I think I
10 was asking a slightly different question, which is not
11 the customer interruptions by cause code in Figure 1. I
12 was asking the source of the tree versus non-tree in
13 reliability, in the reliability model.

14 A So the source of the tree versus non-tree in the
15 reliability model is our, generally our outage, outage
16 data from our OMS.

17 COURT REPORTER: From our what, what
18 letters, OMS?

19 A OMS, outage management system. Apologize.

20 Q (By Ms. Andrews): And is it your understanding that the,
21 that information in the 3.1-01 outages is from the OMS,
22 the outage management system?

23 A Subject to check, I would have to -- I would have to
24 look. It's a pretty big file and --

25 Q O.K. I don't want to get hung up. The Company has
Penn Reporting, LLC - lori.penn@yahoo.com

1 compiled data from trees and non-trees outage events into
2 the reliability model, correct?

3 A Correct.

4 Q And the -- that was my main question, which was the
5 source of the data, and I think you answered it's from
6 the outage data from the outage management system,
7 correct?

8 A That is my understanding, correct.

9 Q Do you know if the outage management system generally
10 follows the same categorization as the outage cause
11 categorization in your Figure 1 on page 16; in other
12 words, are the outages for customer interruptions by
13 cause code the same cause codes for customer outage
14 events?

15 A I guess I would have to check. It's -- I would have to
16 check. It's possible that there are similar cause codes
17 that are, like tree and wind are kind of grouped
18 together, it's possible that there are other cause codes,
19 like weather I think, ICE is a cause code that gets
20 rolled up into weather, so I don't -- while I think that
21 Figure 1 gives you a general idea of what groupings there
22 are, it doesn't necessarily cover every cause code.

23 Q O.k. That makes sense. Do you know if the, if when DTE
24 captures the cause code, it identifies the MED or non-MED
25 information?

1 A Generally, MED and non-MED, my understanding is it is
2 identified by time, by -- there's a statistical formula
3 that determines whether something is an MED or a non-MED
4 day, and that's, it's like a 2.5 beta calculation based
5 on a lot of stuff that I am, can only scratch the surface
6 of. And so the point is we capture it, it's captured
7 based on a statistical formula that determines whether a
8 day goes over an MED threshold or is under an MED
9 threshold based on events, outages, minutes.

10 Q Based on your understanding of the outage management
11 system, if you look at Exhibit, or at MECDE-3.1-01, the
12 outages 2017 through 2023.

13 A Yes.

14 Q Do you see a final column, populated column I?

15 A Yes.

16 Q Would you agree that that column identifies, labels
17 whether an event was storm, non-storm, or MED?

18 A Yes, I agree that that is what the label is.

19 Q And would you agree that MED, those terms, storm,
20 non-storm, and MED are sort of terms of art that the
21 Company uses for various reliability purposes?

22 A I guess I don't understand the term of art phrase.

23 Q I think this goes back to your point that there's a
24 definition of a storm, a definition of when would
25 conditions qualify as a non-storm, and a definition of

1 when conditions qualify as major event day.

2 A I would agree that there is definition for each of those
3 three things.

4 Q Do you know if in the reliability model the Company
5 included storm and non-storm in non-MED?

6 A We included all events that were non-MED.

7 Q Once the Company -- so once -- back to the reliability
8 model. In addition to the baseline performance, the
9 baseline outage information -- let me clarify. These are
10 outage events, correct, these are not customer
11 interruptions or customer minutes interrupted, they have
12 the number of events, right?

13 A Correct. They are number of events per circuit, correct.

14 Q Per circuit. Starting then in column BD, the Company --

15 A I'm sorry to interrupt. Are we back to the reliability
16 model now?

17 Q Yes. I'm looking at columns BD through BG.

18 A I had to confirm, what tab are we on?

19 Q I'm sorry. I'm still on the circuit info and
20 calculations.

21 A Thank you.

22 Q Oh, I'm sorry, you're with me. So those four columns,
23 TT1, TT2, TT3, and TT4, refer to tree trim cycles, the
24 first trim cycle, the second trim cycle, the third trim
25 cycle, and the fourth trim cycle, correct?

1 A Yes, correct.

2 Q And generally speaking, they identify a date that the
3 trim is going to take place, and they're generally about
4 five years apart for each circuit?

5 A They identify a year.

6 Q I'm sorry, a year.

7 A And generally they are about five years apart.

8 Q Which reflects the Company's tree trimming schedule
9 generally?

10 A Generally, that's correct.

11 Q And then PTMM, BH, column BH is PTMM, and then PTMM 2; do
12 you see that?

13 A Yes.

14 Q And generally speaking, that column reflects a treatment,
15 an investment plan for pole top maintenance and
16 modernization for each circuit the year that it would
17 happen first and then a subsequent year that a subsequent
18 amount of PTMM would take place on that circuit?

19 A Sort of. It --

20 Q What did I get wrong?

21 A Well, I'd just note that once the model gets past
22 2029-2030, we're not as concerned with what it says, we
23 just, we don't have visibility on what we're really doing
24 with PTMM. So my point is it says 2034, that's more of
25 just a placeholder input for the model, it's not, it's

1 not representative of an actual plan.

2 Q O.K. Why is it included there if it's not representative
3 of an actual plan?

4 A Because when you build models, you often build them so
5 that you try and future-proof them so you don't have to
6 rebuild the model every time you need to do something in
7 the future. So we have it built in here so when we need
8 it, it's there.

9 Q O.K. The hardening column obviously refers to the
10 hardening program, a year that hardening is scheduled, if
11 at all, for a particular circuit, correct?

12 A Correct.

13 Q CC years is conversion years?

14 A I'd -- let me look, see if I can trace that one back.

15 Q Is that a length of time, how long the conversion will
16 take?

17 A Let me trace that back and I'll see if I can answer your
18 question.

19 Q Sure.

20 A Sorry. This may just take me a second.

21 (Brief pause.)

22 A We're almost there. So again, for clarity, will you
23 repeat your question and I will do my best to answer it.

24 Q What does CC years stand for in column BK on the circuit
25 info and calculations tab?

1 A I believe it just means, if I read the formula correctly,
2 it just means is it in -- it's kind of more of a yes/no
3 thing; does it have a year for circuit conversion in the
4 CC walkdown tab.

5 Q Obviously the conversion year is the year the conversion
6 takes place if it is going to get a conversion, correct?

7 A That is correct. I can't remember if that's the starting
8 or ending year off the top of my head, but yes.

9 Q Automation scheme 1 and scheme 7 refer to distribution
10 automation treatments on particular circuits?

11 A That's is correct.

12 Q What does CE/SRIP stand for?

13 A Customer excellence, and I apologize but I always forget
14 what SRIP means, but it's our, typically our short-cycle
15 programs where we're having kind of maybe some issues on
16 the circuit and we're going in to do usually a small
17 amount of tree trimming and maybe some basic equipment
18 replacement or rehabilitation.

19 Q That's another program that has reliability benefits
20 that's included in that model?

21 A Yes.

22 Q O.K. So generally speaking, would you agree that the
23 tree trim benefits are applied to tree outage events, and
24 all the other programs are applied to non-tree outage
25 events?

1 A No, I would not agree.

2 Q Where did I go wrong?

3 A Maybe, maybe rephrase the question.

4 Q It's my understanding that the tree trimming treatments,
5 the trimming in 2020-2026 result in reductions to tree
6 outage events, not non-tree outage events, correct?

7 A That is correct.

8 Q And then the PTMM hardening conversion automation and
9 CE/SRIP apply to non-tree outage events?

10 A That is incorrect.

11 Q Where did I go wrong? We're narrowing it down.

12 A Sure. Automation applies to both tree trim -- not tree
13 trim -- tree and non-tree events.

14 Q O.K.

15 A And automation does not reduce events, it makes them
16 smaller.

17 Q O.K. We're going to put an asterisk in automation
18 because it's obviously a unique program in terms of how
19 the model treats it; is that a fair assertion?

20 A It is different than how the other programs interact with
21 events, that is correct.

22 Q O.K. So just generally, to orient to the model, for each
23 of the treatment, not including automation, the model has
24 an annual impact across the study period from 2023 to
25 2036 for each event, for tree trimming cycle 1, tree

1 trimming cycle 2, you know, pole top hardening, captured
2 in columns BS through GG, these are the benefits assumed?

3 A I apologize, that was kind of a long and complicated
4 question, so I'm -- maybe if you could break it up or
5 shorten it.

6 Q Sure. Columns BS through GG reflect for each, the
7 conversion, tree trimming programs the projected
8 reductions or degradation for each cycle for each year
9 for each circuit?

10 A O.K. So now kind of moving into the inner workings of
11 the model, and it's complex, and so, so what I would say
12 is for a given circuit, depending on the intervention, be
13 it tree trim, hardening, PTMM, conversion, other, right,
14 it will, if it has a treatment, you will see the impact
15 of the treatment in columns BS through I think you said
16 GG or out farther into the model.

17 Q Yep. And we see pole top and CE and hardening and
18 conversions in columns HA through KZ?

19 A I see, I see PTMM starting at HA through -- what was the
20 final letter?

21 Q I went through KZ, the end of non-tree improvement/
22 degradation (ultimate)?

23 A Were you just talking about PTMM, because I see PTMM
24 through IR, column IR?

25 Q O.K. O.K. We can do it by program. So there's --

1 A Well, I just wasn't -- what's your question, maybe I
2 missed it?

3 Q I'm trying to orient that the model has annual benefits
4 or reductions by program by circuit for each year through
5 20, from 2023 to 2036 for each of the programs that are
6 part of the reliability program.

7 A I believe that to be true, yes, I believe that statement
8 is true.

9 Q O.K. And just to -- if you look at tree trimming, tree
10 trimming first cycle, second, third and --

11 A What column?

12 Q Ultimate. So I'm starting with column DL.

13 A O.K. Back to DL. One second to get there. All right.
14 Back to DL, I'm here.

15 Q Through GH.

16 A Yep.

17 Q Would you agree that the final set, the tree trim, tree
18 improvement/degradation (ultimate) from FT through GG is
19 sort of the cumulation of tree trim cycles first, second,
20 and third?

21 A Yes, with again the note that anything past like I
22 believe it's 2029-2030 is not something that has been
23 validated by the Company in any way.

24 Q O.K. What I would like -- so again, I'm still orienting.
25 In general, the tree trim (ultimate), the cumulation of

1 all the tree trimming benefits across all the cycles all
2 the years is applied to a baseline of tree events, a
3 five-year average of tree events for each year, so
4 starting in column GK, projected non-MED tree multiple-
5 customer outage events. Are you with me?

6 A Yes.

7 Q So the base events is the five-year average for the
8 circuit of non-MED tree multiple-customer outage events,
9 correct?

10 A The five-year average is the baseline by circuit for
11 non-MED tree-related multiple events.

12 Q And then the tree improvement/degradation is applied to
13 that baseline year over year to show the number of events
14 as a result of tree trimming through the cycle, through
15 the study period?

16 A Yes. The tree trim improvement/degradation percentage is
17 applied to the baseline in any given year.

18 Q And then for the non-tree events, conceptually, the model
19 applies the combined benefits of pole tops, PTMM,
20 hardening if there's hardening, conversion if there's
21 conversion, CE/SRIP if that is applied?

22 A I would not characterize it in that way.

23 Q Where did I go wrong?

24 A The way I would characterize it is the cumulative -- let
25 me just go over the model so I get the terminology right.

1 One second, please. So for the projected non-MED
2 non-tree trim multiple events, looking at kind of LB
3 through LR, columns LB through LR, these look at all of
4 the different interventions on a particular circuit and
5 apply the appropriate benefit.

6 Q O.K. I'd like to look at the benefits, the, in
7 particular, the benefit projections for each of the
8 program areas. So if we look at tree trimming, would you
9 agree that the first year, the first year of the trim,
10 there is a 20% reduction applied and then a 40% and then
11 a 30% and then a 25% reduction, and I'm looking at, for
12 example, tree improvement/degradation first cycle, row
13 36, columns starting with DL?

14 A So give me one second, please. O.K. So the way -- the
15 way benefits are weighted, we have calculated benefits
16 for tree trimming. In year one, there is a 40% reduction
17 in tree multiple events, multiple events caused by tree
18 trimming, by trees -- sorry, not by the tree trimming but
19 by the trees. So there's a 40% event reduction in
20 tree-caused multiple events in year 1 post-tree trimming.
21 In year 2 post-tree trimming, there is a 30% reduction in
22 the same thing, tree-caused multiple events. Year 3,
23 there is a 25% reduction. Year 4, there is an 8%
24 reduction. Year 5, we're back to the baseline, that's
25 why we're on a five-year cycle. What the 20% is that

1 you're seeing is year zero, so that's the year in which
2 we are doing the tree trim. And so we make a general
3 assumption for the model that that tree trimming is done
4 at exactly the mid point of the year; there will be some
5 circuits where it's done at the beginning and we get more
6 benefit and some circuits that will be done on the end of
7 the year, we get a little less benefit, but on average
8 for modeling purposes, we assume a mid-year trim and we
9 get half the benefit that year, that's the 20%.

10 Q So if -- and then in, the 8% is a degradation estimation
11 or projection, that's the absence of trimming would make
12 this circuit 8% worse?

13 A Yes.

14 Q O.K. So if you can turn to the, move over to the
15 benefits walkdown and degradation tab.

16 A Yep.

17 Q In general, would you agree that just like -- so if we
18 look at row 77 is TT for tree trim; do you see that?

19 A Row 77?

20 Q 71.

21 A 71, yes.

22 Q And so then just like you said, year zero through year
23 15, and then it's got the benefit, the impact of the
24 treatment projection, estimation, correct?

25 A Correct.

1 Q And so then for -- if we scroll down below tree trim, we
2 see 4.8 conversion singles?

3 A Correct.

4 Q What's a single?

5 A Single event, not a multiple.

6 Q Not a multiple event. And then the next, starting in row
7 114, is pole top and pole test. Conceptually, it's
8 similar to tree trimming where there's a half year, year
9 zero, there's half the benefit of year 1, right?

10 A That is correct.

11 Q And then there's a reduced benefits year over year for
12 the next seven years?

13 A Eight years.

14 Q O.K. So from year 1 through year 8, starting at 30 down
15 to 2% benefit?

16 A (Nodding).

17 Q And then for hardening, the benefits are shown in, where
18 the impacts are shown starting in row 22, hardening, and
19 then it's got the year zero through year 20; do you see
20 that?

21 A Up to 22, you said, yes, I see hardening.

22 Q My question is, who developed the assumptions on the
23 benefits on the programs?

24 A It was a combination of my team, our data analytics team,
25 and our subject matter experts, in particular, our

1 engineers.

2 Q O.K. I'd like you to turn to -- we asked you in
3 discovery and you produced in the rebuttal testimony
4 Exhibit A-43 Schedule HH6, which is your response to a
5 Discovery Request 12.8b.

6 A What was the number, exhibit number again?

7 Q It's your Exhibit A-43 Schedule HH6.

8 A Do you have it in your folder, or do I need to go back
9 out to mine?

10 Q I think you need to go into yours I'm afraid, I didn't
11 put every, your exhibits in your folder, but I could
12 have.

13 A No, no, totally fine. I just want to use our time
14 effectively here. All right. So it's the question
15 MNSCDE-12.8b; is that correct?

16 Q Yep.

17 A Yep, I'm looking at it.

18 Q So you provide a reliability program analysis here,
19 correct?

20 A That is correct.

21 Q And this is the analysis supporting the reliability
22 improvement estimates in the model, right?

23 A Yes, we provide reliability -- yes, correct.

24 Q O.K. So let's start with page 2 that indicates over on
25 the far left TT; is this the tree trim analysis?

1 A I'm just reviewing it. Yes, this appears to be the tree
2 trim analysis.

3 Q The note on the, below the analysis indicates the dates
4 are those are based on January to October. Do you know
5 why only January to October, why it apparently December,
6 November and December were excluded?

7 A I think when we did the analysis -- and again, I did,
8 this was not an analysis that I personally did -- but my
9 suspicion is usually when this happens, it's because we
10 are, because this is a year-by-year analysis and we
11 wanted to include 2022 data, we couldn't -- we had to
12 compare like for like, so likely this analysis was done
13 in November when we did not have November or December
14 data, so to compare like for like year over year, we
15 needed to use January through October data.

16 Q So this analysis was done before the model or as part of
17 development of the model?

18 A It was done at -- it was the necessary precursor to
19 developing the model.

20 Q The circuits -- I'm sorry, I'm looking at my notes.
21 Circuits that were trimmed -- I'm sorry. The analysis
22 shows the number of circuits trimmed in each from 2017
23 through 2021, has the number trimmed as well as the
24 relative weighting given the number of circuit trims. So
25 in 2019, there were 274 circuits trimmed, which was 35%

1 of the total circuits analyzed, right?

2 A Of the circuits that were -- my understanding of this
3 analysis is this is ETTP circuits --

4 COURT REPORTER: I'm sorry. This is what
5 circuits?

6 A ETTP, entranced tree trimming program circuits. So what
7 you're looking at is the number of circuits trimmed to
8 that standard in each of the years. And subject to
9 check, I agree that the percentage, 35%, would be the
10 percentage, the -- it would be basically about 274
11 divided by 75, subject to check.

12 Q (By Ms. Andrews): And basically what you have is the
13 year of the trim is there's a zero percent, and then the
14 year after is N+1, the percent change in events, and then
15 the year N+2 and onward, 3, through the test period, the
16 study period?

17 A Yes, that's correct.

18 Q And then those changes, percent changes in events are
19 compiled and weighted based on the number of circuits to
20 come up with the raw data calculation shown just above
21 the blue box; do you see that?

22 A Yes, correct.

23 Q And so it's N+1 through N+5 and then the percent change
24 in events --

25 A Correct.

1 Q -- raw data? And then the reliability modeling smoothed
2 takes the raw data for tree trimmed, circuits that were
3 tree trimmed, and it evens them out?

4 A I would say it projects what is a reasonable estimate
5 based on what we're seeing in the data.

6 Q There is no N+5 studies, so the zero is an assumption
7 that there would be no change?

8 A That is the assumption.

9 Q Are the year following the tree trimming, is that
10 comparing how many events that year to the event to the
11 preceding year? So if the line was trimmed in 2017, 2018
12 is how many fewer outage events in '18 versus '17?

13 A I believe that is correct.

14 Q Does the -- did this assessment account for the fact that
15 the year the tree was, the circuit was trimmed, some of
16 those circuits wouldn't reflect the benefits, right; like
17 you said, the tree trimming might have happened in
18 February or it might have happened in November, that's
19 not reflected in this assessment, is it?

20 A That is not reflected in this assessment.

21 Q And this doesn't show how the circuit performed before
22 tree trimming versus after tree trimming, correct?

23 A It reflects year zero, the year it was trimmed, versus
24 future years.

25 Q Did the Company validate the tree trim reliability, the

1 reliability modeling assumptions in blue against the
2 Company's annual tree trim data?

3 A I guess I don't understand the question.

4 Q Did the Company check whether 40% reduction in the first
5 year after tree trimming is consistent with what the
6 Company has found in its own assessment of tree trimming,
7 the ETPP effectiveness studies?

8 A This is the Company doing an assessment, we provided it.

9 Q Did you compare this to the assessment of the ETPP that's
10 reported in the Commission dockets?

11 A Which Commission dockets are you referring to?

12 Q I'm referring to the annual tree trim dockets filed in I
13 believe it's 20162?

14 A I am -- I'm somewhat familiar with those dockets. I
15 would tell you it's a different analysis using a
16 different methodology, you cannot compare the two.

17 Q O.K. So the model assumes that every tree trim cycle
18 will produce a 40% reduction compared to the prior year
19 in the first year, correct?

20 A The model assumes that -- I'm sorry. Will you restate
21 that?

22 Q Every tree trim will produce a 40% reduction in outage
23 events the year after the tree trim?

24 A That is correct, that is the assumption of the model,
25 yes.

1 Q O.K. So let's look at hardening, the next section of the
2 analysis, page 3 of the exhibit.

3 A All right.

4 Q The hardening analysis follows the same methodology as
5 the tree trim analysis; is that correct?

6 A That is my understanding, correct.

7 Q It also includes January through October data for the
8 five, the five-year period?

9 A That is correct.

10 Q And it includes data, 2017 there was no hardening, so
11 that is not included in the data set, there's no data for
12 2017, correct?

13 A Correct.

14 Q The number of circuits hardened is shown in the column, a
15 total of 72 circuits were hardened; do you see that?

16 A Yes.

17 Q So this analysis is based on the total of hardening 72
18 circuits from 2018 through 2021, correct?

19 A That is my understanding, correct.

20 Q And because of the nature of the program, there is --
21 there are not -- there are four years worth of post-
22 hardening data, correct?

23 A That is correct.

24 Q As I understand it, there are a total of five circuits
25 that have four years of post-hardening data included in

1 this analysis? I'm looking at N+4-5 towards the right.

2 A I'm sorry, I've lost where you are.

3 Q 72 circuits had N+1 data, hardening, year after hardening
4 data?

5 A Yes.

6 Q 53 circuits had two years after hardening data?

7 A Yes.

8 Q 23 circuits had three years after hardening data?

9 A Yes.

10 Q And a total of five circuits had four years after
11 hardening data, correct?

12 A Correct.

13 Q Looking at the raw data, these were weighted in the same
14 way that the tree trimming circuits were weighted,
15 correct?

16 A Correct.

17 Q Looking at the data, the Company applied a similar
18 smoothing methodology, correct?

19 A Correct.

20 Q Looking back at the reliability model, the benefits and
21 walkdown, benefits walkdown and degradation tab.

22 A Yes.

23 Q Hardening, starting in row 22?

24 A Yes.

25 Q The year zero, 40% is half of year 1 80%, correct?

1 A Correct.

2 Q And the 80% comes from the analysis we just looked at,
3 the first year after hardening analysis shown in Exhibit
4 A-43 Schedule HH6?

5 A That's my understanding, correct.

6 Q And then the 75% is N+2, correct?

7 A Yes.

8 Q So for N+6 through N+15, the 6th through the 15th year
9 after hardening, what's the source of the data?

10 A SME expertise.

11 Q Has the Company validated the accuracy of the 80%, 75%,
12 or 70% for reductions in outage events for circuits
13 trimmed since 2022 or in 2022 and 2023?

14 A Do you mean hardened?

15 Q Hardened. I'm sorry.

16 A I'm confused. This analysis is the validation. We did
17 the analysis based on actual data to populate the model.
18 It's not -- the way we validate it is by doing this
19 analysis.

20 Q The Company hasn't updated the analysis since it was
21 first created, has it?

22 A We have not updated the analysis since we submitted the
23 reliability model, correct.

24 Q Do you have any understanding whether the Company
25 hardened circuits that had worse or better reliability,

1 first prioritized circuits?

2 A That would be a question for Witness Elliott Andahazy,
3 who covers the program and the prioritization of the
4 program.

5 Q Is it your understanding that the first physical step in
6 hardening is a tree trim?

7 A That is correct.

8 Q Does the analysis attempt to isolate the benefits of tree
9 trimming from the benefits of hardening as in crossbar
10 replacement -- crossarm replacements and other capital
11 replacements, that's part of hardening?

12 A Yes, it does separate them.

13 Q In this analysis?

14 A Yes.

15 Q How so?

16 A The analysis looking at hardening is looking at non-tree
17 trim events, not all events, whereas the tree trim is
18 just looking at tree trim events. So the hardening, the
19 tree trim hardening would be found in the tree trim
20 program of this analysis, whereas the hardening would be
21 applied to non-tree trim events in the hardening
22 analysis. That's it.

23 Q And so the Company applied the analysis only using not
24 tree-related outage events, correct?

25 A For hardening.

1 Q For hardening.

2 A For hardening.

3 Q All right. And not, not tree is everything but tree,
4 correct?

5 A Not tree is everything but tree.

6 Q O.K. Let's look at the third page of the Exhibit HH6.
7 This is labeled CE(PTMM Estimate). What does CE(PTMM
8 Estimate) mean?

9 A What -- sorry, repeat your question. I was still getting
10 to the page.

11 Q Sorry. I'm looking at the label on the fourth row on the
12 top left, CE(PTMM Estimate).

13 A Sure. As Witness Elliott Andahazy discusses extensively
14 in her testimony, our PTMM program is a, I don't know
15 what the exact terminology or word she used, but it is
16 more extensive than it has been in the past in terms of
17 the equipment being identified and replaced. Again, I
18 defer to her on this. What I would -- what I would say
19 to you in response to your question is, because it is a
20 program that is similar to tree trim when we kind of
21 moved from what I call the previous spec to our enhanced
22 specification, PTMM is undergoing a similar
23 transformation. As such, we don't have, unlike hardening
24 where we have years of data to rely on, we don't have the
25 same level of data for the PTMM program, and so instead

1 what we did is we took the closest program to it that we
2 had, which is customer excellence, which had been doing
3 similar, you know, in kind of a smaller version, similar
4 work, and we combined that with subject matter experts
5 and came up with combination of data analysis and what
6 we'd expect to see from PTMM based on the new scope of
7 work.

8 Q And based on the new scope of work, do you, by that do
9 you mean when the specifications for poles and pole top
10 replacements were changed?

11 A I'm going to defer that question to Witness
12 Elliott Andahazy, I think she's going to be better
13 prepared to answer your questions regarding any changes.
14 The importance of -- my important point is just that
15 there was a change in the program; Witness
16 Elliott Andahazy can discuss what that is and the details
17 behind it. Because of that, we used a different
18 methodology to arrive at the benefits.

19 Q I want to get two clarifications here. In general, is it
20 fair to say you used a proxy to estimate pole top PTMM
21 reductions?

22 A In part.

23 Q And what's the other part?

24 A The other part is subject matter expertise.

25 Q And just for clarity, any PTMM treatment between 2019

1 through 2021 was not included, the circuits that were
2 under a program called PTMM were not included in the
3 reliability program analysis?

4 A That is my understanding.

5 Q O.K. So let's look quickly at the data. CE is the, is
6 my term, not yours, the proxy program, it includes a
7 targeted capital investment in a circuit to improve
8 reliability, generally, correct?

9 A Correct.

10 Q As I understand it, in year 1 following the CE program,
11 the first, in 2019 was a 58% reduction and a consistent
12 reduction in year 2 after trimming or CE?

13 A The 2019 you said 58% and then another 58%, I agree with
14 that.

15 Q And there were a total of 105 circuits included in this
16 assessment, correct?

17 A Well, the 58 and 58 seems like there's 11 circuits as
18 part of that dataset.

19 Q Oh, I'm sorry. The entire analysis reflected on page 4,
20 the 100% of circuits is 105 circuits, total 105 circuits?

21 A I agree.

22 Q Let's look at the raw data. The raw data calculation
23 above the blue box indicates that in the first year after
24 CE, there was a 13% reduction in outage events, correct?

25 A Correct.

1 Q The second year, 21%, correct?

2 A Correct.

3 Q And then the third year, there was a 31% reduction?

4 A Correct.

5 Q And in the fourth year, there was no improvement, no
6 reduction?

7 A That is correct. But also zero, if you look, there's
8 zero circuits in that population.

9 Q So looking at the 54 circuits that were, that received CE
10 treatment in 2021, the data shows that the year, the
11 first year after was a, they were 2% worse than the year
12 they were treated; do you see that?

13 A I do.

14 Q What's the explanation?

15 A I would have to go in and look at this particular set of
16 data to see if it was weather or if it was some other
17 factor. So yeah, I would have to go in and look at this
18 particular subset. That's why we look at things,
19 especially for data like this, because of weather and
20 other variability, that's why we try and get as big a
21 dataset as possible for statistical significance. We
22 don't look at 58% or the -- 58% less or the 2%, we pool
23 them together.

24 Q And the N+1 between the raw data and the smoothing went
25 from 13% to 30%. What's the explanation there, how does

1 13% become 30% in smoothing?

2 A Well, like I've already mentioned on I think a couple of
3 different occasions, this was a combination in this case
4 between not just data but SME expertise, and so when we
5 look at the data, it doesn't, you know, just -- it's
6 noisy, right, this is noisier data, there's less of it,
7 and so you have 13, 21, 31, so that's indicating that we
8 are seeing some improvement in this program, but it also
9 is getting better over time, which is typically not
10 what's happened -- what typically happens, and so that's
11 an indication that there's probably some weather
12 variability or some other weather variability in the data
13 that's impacting. So we take that data, we use it as
14 kind of a rough guide, and then we apply SME expertise to
15 figure out what we think a reasonable trajectory for the
16 PTMM program is; and then our process going forward then
17 is to monitor the data every year and improve with the
18 analysis.

19 Q So has the Company monitored data since this assessment
20 was compiled in I think you said November of 2022?

21 A What was the word you used?

22 Q Has the Company monitored the data, I think you said -- I
23 think you said you monitor data?

24 A We have not redone this analysis. What we are waiting
25 for is enough time to go by from when we had done our,

1 again, for lack of a better term, our enhanced PTMM
2 program. I don't know that that's the right terminology,
3 so forgive me, subject to check. Witness Morgan --
4 sorry -- Witness Elliott Andahazy will be able to address
5 that more holistically. What I'd say is, from my data
6 analytics perspective, we're looking for that data and we
7 will use that, as I discuss in my direct testimony, to
8 update the reliability model.

9 Q The Company could have -- does have all year data at
10 least through the entire 2022 for the -- since this
11 report was done, right? You could have updated the
12 months that were excluded, November and December?

13 A I believe it is possible to update the analysis, that's
14 correct.

15 Q And could have added it one more year, 2023?

16 A Well, today, yes, we probably could add 2023.

17 Q That would help eliminate some of the noise, so to speak,
18 in the data?

19 A At the time the model was constructed, this was the
20 analysis that was completed.

21 Q So when we go back to the model, again, the benefits
22 walkdown and degradation tab, starting in row 133 -- I'm
23 sorry, nope -- starting in row 114, pole top and pole
24 test 2023 plus, are you with me?

25 A Yes.

1 Q Would you agree with me that the, the benefits or the
2 impacts of the pole top program, the Company extrapolated
3 or determined the benefits for years beyond, what was it,
4 year 3 using subject matter experts?

5 A I would agree with that.

6 Q And going back to the top of the tab, of the sheet,
7 there's, starting in row 3, there's PTMM
8 pre-2023/enhanced specs; do you see that?

9 A Yes.

10 Q And generally, it shows zero-percent benefit in every
11 year for those, for that, for those circuits, correct?

12 A Correct.

13 Q And so if we go back to the circuit info and calculations
14 tab, in column BH where the Company shows PTMM, the
15 first, the first cycle of PTMM, there are circuits where
16 the Company applied PTMM to those circuits, so example,
17 row 21 received PTMM in 2022; do you see that?

18 A Correct.

19 Q It's, the model assumes that that PTMM treatment provided
20 zero benefits going forward, correct?

21 A That is the assumption the model makes, correct.

22 Q So it's only in 2023 that the model starts to apply PTMM
23 benefits?

24 A That is correct.

25 MS. ANDREWS: Your Honor, this would be a
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1 good time to take a quick break for me to gather my
2 perspective.

3 JUDGE WALLACE: O.K. Let's go off the
4 record for 15 minutes.

5 (Recess from 2:31 p.m. until 2:48 p.m.)

6 JUDGE WALLACE: All right. We're back on
7 the record.

8 Q (By Ms. Andrews): All right. Mr. Kryscynski, I have
9 another question related to the automation benefits. If
10 you can look at circuit info and calculations tab on the
11 reliability model.

12 A Yes.

13 Q Looking at column BO and PP -- BP, automation scheme 1
14 and automation scheme 7; do you see those?

15 A I do.

16 Q Generally speaking, at a high level, do you -- what is
17 the difference between automation scheme 1 and scheme 7?

18 A Automation scheme 1 at a high level is a startup circuit
19 (inaudible) --

20 COURT REPORTER: I'm sorry. A startup
21 circuit?

22 A Startup circuit recloser, so a recloser placed at the
23 beginning of the circuit, often referred to as the
24 station cable pole, pole, p-o-l-e, cable pole; and
25 automation scheme 7 is what we would refer to as a loop

1 scheme, which is made up of generally, at a minimum,
2 three reclosers -- well, three reclosers on a circuit,
3 two-and-a-half circuit, closers on a circuit, so that
4 would be a startup circuit recloser, a midpoint recloser,
5 and a tie recloser which it shared with another circuit.

6 Q (By Ms. Andrews): Generally, the Company has initiated
7 some of the automation scheme 7, from what I understand?

8 A That is, that is my understanding as well, although I
9 would direct you for details to Witness Hartwick.

10 Q And is it your understanding that automation scheme 1 has
11 not yet been initiated, or you said at the time the model
12 was made, there were no existing circuits with automation
13 scheme 7 in the analysis, in the model?

14 A I would have to check. I don't know that that's true,
15 but I would have to check.

16 Q O.K. So let's look at the automation benefits by circuit
17 tab. You mentioned early --

18 A Got it.

19 Q Thank you. You mentioned earlier that automation is
20 different because it doesn't reduce the number of events,
21 it reduces the number of customers experiencing an event
22 or the duration they experience an event; do I have that
23 somewhat accurate?

24 A I believe so. Automation does not reduce the event,
25 ideally it makes the event smaller by minimizing the

1 number of customers affected, which reduces both the
2 customers affected or interrupted as well as the overall
3 minutes for the outage.

4 Q In overall -- sorry -- the scheme 1 overall CI reduction,
5 CI refers to customer interruptions, correct?

6 A Correct.

7 Q And according to the benefits, there is either a zero, an
8 18 or a 36% reduction applied; is that correct?

9 A That is correct.

10 Q And what is the source of those impacts, projections?

11 A I would have to -- I believe it's SME/engineering, I
12 would have to check to confirm.

13 Q O.K. And then the overall CMI reductions, what, do you
14 know, those are also hard entered, do you know what the
15 source of those reductions is?

16 A Again, my understanding is this is SME/engineering.

17 Q O.K. And then over on scheme 7, which is shown in
18 columns F and G, same question, do you know if -- are
19 those SME inputs to determine the CI and CMI reductions?

20 A SME, yes, SME inputs, although, again, I would, I would
21 need to check with -- I'd have to check with my support
22 team to confirm the source of the data.

23 Q These are projected benefits for the program going
24 forward, correct?

25 A Correct.

1 Q I'd like to look back at the benefits walkdown and
2 degradation tab. Are you with me?

3 A Yes.

4 Q Degradation multiple customers, 8%, do you see that in
5 row 3?

6 A I do.

7 Q I believe we asked you in discovery for the source of
8 that assumption or that 8% reduction -- degradation.
9 Just in general, would you agree that degradation is, at
10 least you mentioned earlier that the status quo absent
11 the various treatment programs or interventions I think
12 you called them, that the system would degrade to 8%?

13 A Sorry, that question was a little bit --

14 Q Sorry, yeah.

15 A -- difficult.

16 Q I'm trying to shorten our analysis. We already talked
17 about what the degradation analysis is, it's the sort of
18 status quo absent the various interventions?

19 A Correct.

20 Q So if you look at what's labeled as Exhibit MEC-67 in the
21 folder, we asked you for the source data employed by the
22 model to estimate impact of system degradation, and you
23 produced the analysis on page 2 of the proposed exhibit;
24 do you see that?

25 A Yes.

1 Q Why did the Company choose the period from 2008 to 2017
2 to assess degradation?

3 A Because it was a period of time where we were not doing
4 much capital or strategic investment, so we could look at
5 the system overall with very little investment noise.

6 Q This precedes the enhanced tree treatment program as
7 well, doesn't it?

8 A It does.

9 Q Is it your understanding that these are outage events,
10 both tree and non-tree outage events?

11 A That is my understanding, correct.

12 Q O.K. Now, you would agree that the data, I would hate to
13 characterize something as wild, but there is a
14 substantial variation year over year in the number of
15 non-MED outages during the study period; would you agree?

16 A Say that question again.

17 Q There's a substantial variation year over year, the
18 change from 7% reduction one year to a 14% increase the
19 next year, there's a lot of variability in the number of
20 non-MED outage events year over year?

21 A I guess that's a matter of opinion. I don't know that I
22 would agree with that.

23 Q Your analysis is that there's a, basically an 8%
24 trendline, so to speak, through the data?

25 A It is the Company's analysis, it is not the analysis I've
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1 personally done.

2 Q O.K. That 8% degradation rate is applied to both
3 non-tree and tree MED -- sorry -- they're all excluding
4 MEDs -- tree and non-tree outage events in the model,
5 correct?

6 A Subject to check, that is my understanding.

7 Q O.K. Looking back at the model --

8 MS. ANDREWS: Your Honor, sorry, before I
9 forget, could I move for the admission of Exhibit MEC-67?

10 JUDGE WALLACE: Is there any objection to
11 the admission of Exhibit MEC-67?

12 Hearing none, the exhibit is admitted.

13 Q (By Ms. Andrews): All right. We're getting close. I'd
14 like to look at how events and reduced events are the
15 basis for the customer interruptions and customer minute
16 interruptions assessments in the model. So as I
17 understand it, the model shows non-tree post-intervention
18 outage events, non-tree multiple outage events in I want
19 to say column VI -- make sure I'm right here. So after
20 the baseline and after all the interventions are applied,
21 there's a number of events, baseline a number of events
22 for all, all circuits, all years, correct? I'm sorry.
23 I'm looking for the collection here. Single, single --
24 so columns LD through LR show non-tree non-MED multiple-
25 customer outage events after all the interventions, the

1 benefits of the assumed interventions that the assumed
2 dates are shown, correct?

3 A Try that question again.

4 Q Yep. LD through LR shows projected non-MED non-tree
5 multiple-customer outage events relative to the baseline
6 after all the interventions are applied?

7 A If I followed that question, and I think I did --

8 Q This is the summation of the benefits --

9 A This is the summation of the events. So based on the
10 interventions that we have talked about, whether a
11 circuit has had that, those interventions or not, this is
12 the summation of the events post-intervention or lack
13 thereof.

14 Q And I'm looking for -- there's a lot of data in this
15 spreadsheet. I'm looking for the non-MED tree outage
16 events summation. You might get there quicker than me.

17 A I'm not -- I believe it is in G --

18 Q Yep.

19 A Go ahead.

20 Q I think it's GK through GY?

21 A Yes. I'd say GL through GY.

22 Q O.K. Yep. GK is the five-year. So in order to convert
23 the number of outage events, tree and non-tree outage
24 events, into customer interruptions, the Company -- and
25 I'm looking now at column UP; are you with me?

1 A I am.

2 Q So basically the Company multiplied for each year the
3 event times the number of customers interrupted to figure
4 out the number of customer interruptions per year per
5 circuit through the study period, correct?

6 A Please restate.

7 Q Conceptually, methodologically, the Company multiplied
8 the number of events times number of customers to get the
9 customer interruptions?

10 A I would rephrase that and say the Company, and I'm
11 looking at UP through VC, this area, we are multiplying
12 the events from the previous columns we were just looking
13 at times the number of minutes we would expect to see on
14 average -- sorry -- number of customers -- sorry, this is
15 interruptions -- number of customers we would expect to
16 see interrupted in an average tree multiple-customer
17 interruption.

18 Q And to clarify, this is not based on the number of
19 customers on the circuit, it is based on an average
20 number of customers by voltage level during a multiple-
21 customer outage event, correct?

22 A I believe that to be true, subject to check.

23 Q So if we look at row 12 and we go back to, this is tree
24 event, so if we go back to L -- I'm looking for projected
25 tree events -- column GL says the number of events is 2

1 in 2023, and the fact that there are 1,166 customers on
2 this circuit is not the basis for the customer
3 interruptions, correct? I'm looking at column I, row 12,
4 1,166 customers.

5 A All right. Just trying to get back to where we were. Do
6 you remember what columns we were in off the top of your
7 head?

8 Q I believe GL.

9 A No, I'm sorry. The -- we were farther back.

10 Q Customer interruptions?

11 A Yes.

12 MS. HAYDEN: It was UP, column UP.

13 MS. ANDREWS: Thank you. UP, yep.

14 Q (By Ms. Andrews): Let me ask a different question.

15 A Sure.

16 Q The customer interruptions is agnostic to the number of
17 customers on the actual circuit, correct?

18 A That's what I was trying to check right now to confirm
19 that that is accurate. So just going to require me to
20 look at a formula for a second and trace back through the
21 model. So the number of customers in the customer
22 interruption for tree multiple-customer outages in
23 columns UP through looks like (inaudible) --

24 COURT REPORTER: I'm sorry. BZ?

25 A Sorry, I know this fun.

1 COURT REPORTER: No, it's very fuzzy,
2 your connection is very fuzzy.

3 A UP, so up in this case, UP through VC, those columns are
4 calculated by taking the projected events by year for
5 each circuit, accounting for any automation benefits, and
6 then using a standard customer interruption per event.

7 Q (By Ms. Andrews): And the standard customer interruption
8 per event comes from the tab labeled assumptions by
9 voltage?

10 A That is correct.

11 Q And in particular, the assumptions by voltage shows
12 customer interruptions per events and customer minutes
13 interruptions per events, CINT and CMINT?

14 A Yes.

15 Q And it breaks those down by both MED, and non-MED tree
16 and non-tree multiple and single, correct?

17 A Correct.

18 Q And then, for example, at 4.8 kV circuit, the, for a tree
19 multiple events, it is assumed, non-MED, that there is,
20 there are 70 customer interruptions per event, correct?

21 A That is correct, yes.

22 Q And then for customer minute interruptions, the same
23 methodology applies, number of events based on the
24 voltage based on whether it's tree, non-tree, multiple,
25 single, MED, non-MED, the number of events times the

1 customer minutes per interruption per event?

2 A That is correct.

3 Q So my question earlier, the projected customer
4 interruptions, non-MED tree multiple-customer outage
5 customer interruptions is agnostic to the number of
6 actual customers on a particular circuit, it's based on
7 the average?

8 A Each event is based on the average, that is correct.

9 Q And that is also true of the customer minutes
10 interrupted, correct? So columns --

11 A Let me clarify my previous answer. Each event is based
12 on the average using this tab assumption by voltage, and
13 so there are different averages for different events with
14 different characteristics.

15 Q So you would only apply tree-to-tree outages and
16 non-tree-to-non-tree, multiple-to-multiple, single-to-
17 single?

18 A MED-to-MED, yep, correct.

19 Q All right. And the same applies, right, so the same
20 analysis applies to both tree and non-tree, including the
21 addition of the automation reductions, everything we just
22 said about trees is also true of non-trees?

23 A To the best of my knowledge, that is correct.

24 Q I think you said distribution automation benefits apply
25 to both tree and non-tree events?

1 A That is correct.

2 Q O.K. I would like to go back to your rebuttal -- your
3 direct testimony where you indicated that, on page 69,
4 the Company's reliability model projects that customers
5 will experience an all-weather SAIDI of 504 minutes in
6 2024 versus a historical baseline of 563. Are you with
7 me?

8 A Yes.

9 Q Yes. So we just walked through the model all the way
10 through the total number of customer interruptions and
11 customer minutes interruptions for tree and non-tree
12 multiple; the same applies to single, correct, generally?

13 (Multiple speakers.)

14 COURT REPORTER: I'm sorry. Your answer?
15 You were both talking at once. Your answer.

16 A I think my answer was generally.

17 COURT REPORTER: Thank you.

18 Q (By Ms. Andrews): The benefits are summed for SAIFI,
19 SAIDI, and CAIDI, correct?

20 A I'd have to go to the part of the model that you're
21 talking about.

22 Q So how do we get from -- because we're sort of at the end
23 of the line on circuit information and calculations, it
24 is still broken down by non-MED non-tree single, non-MED
25 tree single, right; how do we -- how does the model

1 compile all of the components into the SAIDI reduction?

2 A What -- can you be more specific on the SAIDI reduction?

3 Q So in your testimony, you say the Company's reliability
4 model projects that customers will experience an
5 all-weather SAIDI of 504 minutes in 2024, and I'm trying
6 to get from the customer minute interruptions in
7 particular from the various components to an all-weather
8 SAIDI. Can you walk through how the model gets us from,
9 from the components to -- and why don't we start with
10 SAIDI excluding MEDs, why don't we back up a step. How
11 does the model compile all the results into a SAIDI
12 excluding MEDs?

13 A So let me take a look.

14 Q Yep.

15 A I will confirm this, but my expectation is for all of the
16 different components, for events, number of events for
17 customer interruptions and for SAIDI minutes, all of
18 this, and excluding MEDs, they are summed, the components
19 are summed together.

20 Q O.K. And that's in the reliability projections tab?

21 A I would have to go through the exact model to confirm
22 that, but conceptually, that's what I believe is
23 happening. If you want me to confirm exactly what the
24 model is doing, I'm going to have to go through each cell
25 of the model and make sure that I'm correct.

1 Q So I'd like to refer you to the reliability projections,
2 it's a green tab in the model.

3 A Yes.

4 Q It starts with the word output.

5 A Yes.

6 Q And I would draw your attention to row 30, customer
7 interruptions --

8 A Yes.

9 Q -- CINT. Are you with me?

10 A Correct, yes I am.

11 Q Would you generally agree with me that the four rows
12 underneath row 30 under CINT reflect the four buckets of
13 customer interruption summations from the circuit info
14 and calculations spreadsheet?

15 A Give me one moment here. Yes, that appears to be
16 correct.

17 Q And similarly, for customer minutes interrupted or CMINT,
18 the model follows the same methodology, rows 38 through
19 41 are the summation from the circuit info and
20 calculations tab for each year for each bucket of --

21 A Let me just, I want to check one thing real quick.

22 Q -- outages? Sure.

23 A Yes, I agree with that.

24 Q And then what's the, the four buckets of events for each,
25 customer interruptions and customer minutes

1 interruptions, are, the totals for both, for customer
2 interruptions and customer minutes, are shown in lines 44
3 and 45 for customer interruption to custom minutes
4 interruptions respectively?

5 A I agree, yes.

6 Q And as is reflected in the label, these are non-MED
7 customer interruptions and customer minutes
8 interruptions, correct?

9 A That is my understanding, correct.

10 Q And to get it from non-MED to all weather, or including
11 MED, the model scales up each, customer interruptions and
12 customer minute interruptions, correct?

13 A That is correct.

14 Q And it's scaled up using the AW event scale up and
15 customer base tab, correct?

16 A It's scaled up using data from that tab, correct.

17 Q Thank you. And the scale up from non-MED to all weather
18 is based on average, low, medium, and high what, what do
19 we call those, years, MED, what are we -- what is
20 average, low, medium, and high probability?

21 A What tab are you on, just so I can be looking at the same
22 thing you're looking at?

23 Q AW event scale up and customer base.

24 A Sorry. Give me a second. So I -- I'm a little confused
25 where you're going here. So if I'm looking at the

1 reliability projections tab, which we were, this is where
2 we started on, and -- maybe I'm missing something here.

3 All right, give me -- I'm sorry, go ahead.

4 Q I'm trying to understand conceptually how the scale up
5 works, and more particularly, what's the difference
6 between a low, an medium, and a high all-weather
7 projection, SAIDI all weather, SAIFI all weather, or
8 CAIDI all weather, just those labels low, medium, and
9 high, what do they generally mean?

10 A I understand what your question is. This is a fairly
11 complex formula, so it's going to take me a little bit to
12 walk it back, so --

13 Q Let me see if I can simplify it. Is it fair to say that
14 the reliability model is attempting to reflect that there
15 are all-weather years where SAIDI is high, where SAIDI is
16 low, and where SAIDI is somewhere in the middle year over
17 year given the variability in weather, conceptually?

18 A I think conceptually, that is correct. What I am unable
19 to answer at this exact moment without having to dig
20 through the model is, so if you look down below, we
21 looked at quartiles, right, and so I talk in my
22 testimony -- maybe I can just flip to it quickly. So
23 here on question 89, so we ask: How are -- I ask
24 myself -- How are Ex-MED and all-weather reliability
25 metrics calculated; and so the primary output of the

1 model, as we have gone through, is ex-MED event volume,
2 which is translated into SAIFI ex-MED and SAIDI ex-MED
3 using historical event averages, and so I think we've got
4 to that. But the ex-MED results are scaled to
5 all-weather projections by calculating the ex-MED to all
6 weather performance relationship of 64 large utilities
7 based on historical data available on EIA.gov. As an
8 example --

9 COURT REPORTER: I'm sorry. As an
10 example? Are you -- please.

11 A Apologize. As an example, for utilities who had a SAIDI
12 ex-MED of 100 minutes in a given year, the range of
13 all-weather SAIDI outcomes, excluding the top and bottom
14 20%, was 140 minutes to 342 minutes. So if the model
15 projects that the Company's SAIDI ex-MED performance to
16 be 100 minutes, it would also calculate a range of
17 all-weather outcomes to be 140 to 342 minutes. The
18 specific method of calculation I would have to dig into
19 to explain, because there are percentiles that are being
20 pulled from benchmarking data as well as that other tab,
21 and I, I would need time to go through it or consult with
22 my team to like be able to give you a very detailed
23 answer on the calculation of exactly in the model how
24 that works. It can be done, I just need time to do it.

25 Q We don't need to do that. What I'm trying to understand

1 is, conceptually, that the Company determined the range
2 of all-weather SAIDI based on SAIDI ex-MED across other
3 utilities, and then if SAIDI ex-MED across other
4 utilities was X and then looked at their all-weather
5 SAIDI, those were the benchmarks that DTE used,
6 conceptually?

7 A Yes. 63, I think it's 63 utilities over a range of --

8 Q O.K. And one question I have for you, so if I look at
9 column E, row 17, SAIDI all-weather DTE for baseline,
10 which is the five-year period from 2017 to 2022, correct?

11 A You pivoted a little too fast and I wasn't able to keep
12 up with where you were going.

13 Q Reliability projections tab.

14 A Yes.

15 Q Column E, baseline, row 17, DTE, the 563 SAIDI
16 all-weather minutes is what's shown in your testimony,
17 correct?

18 A Correct.

19 Q And then the projection from the model for all-weather
20 SAIDI for 2024 of 504 is shown in column F, row 17,
21 correct?

22 A Correct.

23 Q Would you agree with me that the 563 is a five-year
24 average?

25 A The 563?

1 Q Yep.

2 A Yes.

3 Q Is the 500 -- is 504 a five-year average or the one-year
4 SAIDI?

5 A It is the projected one-year SAIDI assuming an average
6 year.

7 Q O.K. And the 487 for 2025, it looks like it's for 482.
8 Is that a typo in your testimony? Page 12 -- I mean
9 sorry. Page 69, line 12, just making sure I'm not
10 looking at the wrong place in the model.

11 A It could be a typo in my testimony, I would have to
12 check.

13 Q O.K. All right. In general, the DTE, row 17, shows the
14 projected one-year SAIDI for each year that, of the
15 model, correct?

16 A Yes, assuming a normal average year.

17 Q Looking back at the circuit info and calculations tab,
18 the study period went from 2023 to 2036, correct?

19 A The model goes from 2023 to 2036. As I have already
20 stated, that anything past 2029-2030 is not, not data
21 that has been vetted in any significant way and was not
22 presented in this rate case.

23 Q My question is, how did 2023 do? 2023 was included in
24 the study, but it's not included in the reliability
25 projections. Do you know how the, how the model

1 projection all-weather SAIDI for 2023 fared relative to
2 actual DTE SAIDI, all-weather SAIDI in 2023?

3 A I don't believe the model projects 2023, unless I'm
4 mistaken.

5 Q Well, the model produces every component of the
6 assessment, right, the number of customer minutes
7 interrupted, number of customer interruptions, tree,
8 non-tree, single, multiple, for 2023 through 2036?

9 A Perhaps, but the model does not predict 2023.

10 Q But the model, the model could be validated, the accuracy
11 of the model predictions could be validated using 2023,
12 correct?

13 A I would have to think through that, if we could do that
14 or not. I'm not -- I haven't thought through that
15 question, I do not know.

16 Q All the components of the SAIDI all-weather projections
17 and SAIFI and CAIDI are available for 2023 as well as
18 2024 and onwards, correct?

19 A I do not know, I would have to validate it. I do not
20 know the answer to your question.

21 MS. ANDREWS: Your Honor, at this point I
22 would move for the admission of Exhibit, I'm going to
23 call it MEC-72, which would be the working workpaper
24 version of the reliability model.

25 JUDGE WALLACE: Is there any objection to
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1 the admission of Exhibit MEC-72?

2 Hearing none, the exhibit is admitted.

3 Q (By Ms. Andrews): I just have a handful of questions for
4 you, Mr. Kryscynski, related to Exhibit MEC-26 that was
5 discussed yesterday during the cross-examination of
6 Foley. If you would like to take a break before we do
7 that, we can. I'm not sure if you were watching his
8 testimony yesterday.

9 A I saw some of it, but not all of it. And yeah, if you
10 don't mind, I wouldn't mind a bathroom break.

11 Q O.K.

12 JUDGE WALLACE: Off the record for what,
13 ten minutes?

14 MS. ANDREWS: That sounds fine.

15 (Recess from 3:35 p.m. until 3:55 p.m.)

16 JUDGE WALLACE: All right. Back on the
17 record. Please go ahead, Ms. Andrews.

18 MS. ANDREWS: Thank you, your Honor.

19 Q (By Ms. Andrews): Mr. Kryscynski, if you can look in the
20 SharePoint folder for Exhibit, what's been labeled
21 Exhibit MEC-26, which was admitted into the record
22 yesterday.

23 A Yes.

24 Q I'd like to bring your attention to an email exchange
25 that begins on page 29 of the exhibit, and it moves

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1 forward, so to speak, to page 26 since the email sort of
2 includes --

3 A Yes.

4 Q -- some historic emails. Are you with me?

5 A I am.

6 Q So in general, just for orientation purposes, on
7 February 7, Neal Foley initiated an email with Mr. Paul.
8 You know who those individuals are?

9 A I do.

10 Q And the subject matter was, subject line was Updated IRM
11 Expansion Proposal for Review. Do you see that?

12 A Yes.

13 Q A few days later, on February 9, you and others are
14 looped into the conversation, and one of the discussion
15 points is introducing PTMM into the IRP, I mean into the
16 IRM, among other things, just for context.

17 A (Nodding).

18 Q Are you with me?

19 A I'm with you.

20 Q So then I'm on page 27 at the bottom of the page, you
21 raise concern about putting PTMM in, and I assume by in
22 all the way, you mean in the IRM all the way; is that
23 your understanding?

24 A What I meant was put the entire PTMM program and all of
25 its investment dollars into the IRM.

1 Q O.K. Then there's, jumping forward to February 9 at
2 10:13 p.m., there's an email from you to everybody who's
3 on the email chain, and it says: As an FYI if it impacts
4 the final decision, I had an interview this week with the
5 auditors. Are you following along?

6 A I am.

7 Q And it goes on to say: I got a very strong impression
8 that they are going to come out in firm support of an
9 expanded PTMM program. I think we might have some wind
10 in the PTMM sails post audit report. Do you recall this
11 email exchange?

12 A I have read this email exchange, yes.

13 Q My question for you is, what did the auditor say that
14 gave you a very strong impression that they were going to
15 come out in firm support of an expanded PTMM program?

16 A It's a feeling that I had based on the interview I had
17 with them. I don't remember specifics other than I got
18 the strong impression that they felt that PTMM, pole top
19 inspection type program was essential to improved
20 reliability performance. That was the impression I got.

21 Q Who else was at that meeting?

22 A I do not recall.

23 Q Was it your first meeting with the auditors?

24 A I do not recall.

25 Q Were you provided anything in writing from the auditors

1 at that meeting in early February?

2 A I can't imagine I would have been. I don't recall.

3 Q Looking at page 19 of the exhibit --

4 A Yes.

5 Q -- this is an email from Mr. Bruzzano to a series of
6 people, yourself included, on February 23. Do you recall
7 receiving this email?

8 A I don't recall receiving this email.

9 Q You --

10 A But I --

11 Q You --

12 A I've read it, I've familiarized myself with it.

13 Q The second paragraph of the email says: Recognizing that
14 I was a voice of opposition on this given prior
15 Commission signals, things seem to be shifting
16 significantly, especially post February 15 meeting. PTMM
17 could now be an easier program to get into the IRM than
18 the rapid expansion of Automation. What is your
19 understanding of the February 15 meeting?

20 A I do not -- I wasn't -- I don't know of that meeting, I
21 don't think I was part of that meeting, but I do not
22 recall it.

23 Q Who would -- what is your understanding of who
24 Mr. Bruzzano would meet with that would give him an
25 impression, such an impression?

1 MS. HAYDEN: Object to foundation.

2 Mr. Kryscynski has testified he doesn't know what the
3 meeting is.

4 Q (By Ms. Andrews): You have no recollection of the
5 February 15 meeting referenced in the email?

6 A Am I to answer that? I have no recollection of the
7 February 15 meeting in the email.

8 Q On page 18 of the exhibit, about 30 minutes later, about
9 8:30 in the morning, you responded to Mr. Bruzzano. You
10 see the email I'm referring to?

11 A Yes.

12 Q Another data point - I had another meeting with the
13 auditors yesterday and they said that the two programs
14 they feel are highest priority are 1) Tree Trim and 2)
15 PTMM. There is very little chance that the audit report
16 doesn't come out very strongly in favor of increased
17 investment in this area. What -- tell me everything you
18 remember about what the auditors told you at their
19 February, on February 22 about PTMM.

20 A This is seven months ago, six to seven months ago. I
21 remember generally the feeling I had after I met with
22 them. I think I met with them twice during this period
23 of time, that is my recollection, although it's possible
24 it could have been one time or three times, but I believe
25 it was twice. My general impression upon talking to them

1 was they were very strongly in favor of tree trim and
2 PTMM type programs, pole top programs. That is the
3 general impression or feeling I got that I am
4 communicating in this email.

5 Q How many auditors did you meet with?

6 A Usually there were two to four of them present.

7 Q You said there might have been one or there might have
8 been two or three. There were at least two, correct?

9 A Auditors?

10 Q I'm sorry. Meetings with auditors.

11 A I believe there were two, correct.

12 Q There may have been more?

13 A I have met, during this time period, my best, as I've
14 already stated, my best guess is that there were two.
15 Could have been one and I'm misremembering things, could
16 have been three and I'm misremembering things, but my
17 best guess given my recollection is that there were two.

18 Q There was one preceding the February 9 and there was one
19 on February 2 at least, correct?

20 A February 2?

21 Q I'm sorry. February 9. You said: I had an interview
22 this week with the auditors. That was on February 9.

23 A So it would have been the week of February 9, whatever
24 that week was. According to --

25 Q And then another -- another meeting with the auditors

1 yesterday, so February 22, right?

2 A That appears to be accurate, given the emails.

3 Q Did you have any meetings with the auditors since
4 February 22?

5 A Yes.

6 Q When did you meet with the auditors since February 22?

7 A Multiple times, I don't have a list.

8 Q Did you talk about the PTMM program after the February 22
9 meeting?

10 A We have talked about many programs, including the PTMM
11 program.

12 Q Approximately how many times have you met the auditors
13 since February 22?

14 A Since February 22? My best estimate is between five and
15 ten times.

16 Q How about before February 2 -- 22?

17 A I believe February 2 was probably my first interview with
18 them.

19 Q Was anything provided to you by the auditors at any of
20 the meetings you attended?

21 A I don't believe that -- I -- I don't believe so. I don't
22 believe so, not to me.

23 Q Who else from DTE was at the meetings with the auditors
24 either before or after February 22?

25 A There have been multiple interviews with multiple people,
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1 that's I think kind of by definition the nature of the
2 audit.

3 MS. ANDREWS: O.K. Your Honor, at this
4 point I have a series of exhibits I would like to admit
5 without questions, and I can go through those. I think
6 there actually was an error in one, and it might have
7 been fixed, it might not have been fixed just yet. So I
8 would move -- and I would encourage the witness to look
9 at the exhibits first, unless he already has, but I would
10 move for the admission of the following exhibits that
11 were loaded into the SharePoint file: Exhibit MEC-28,
12 which is the response to MNSCDE-17.21; MEC-29, which is a
13 response to MNSCDE-17.16b; MEC-30, which is the response
14 to MNSCDE 17.24; MEC-31, which is a response to
15 MNSCDE-18.7; MEC-32, which is the response to
16 MNSCDE-18.10; MEC-33, response to MNSCDE-19.37a through
17 d; MEC-34, response to MNSCDE-15.20c; MNSCDE- -- sorry --
18 MEC-35, which is the response to MNSCDE-17.19, together
19 with the response to MNSCDE-3.1a and an excerpt from the
20 cited spreadsheet; and finally, Exhibit MEC-38, which is
21 the Company's filing in Case No. 12270, the 2023
22 Reliability Report.

23 JUDGE WALLACE: Now, you said there was
24 one exhibit that might have an error in it?

25 MS. ANDREWS: Oh, I'm sorry. The header
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1 on 34 was missing and on 35 said 34, but it may already
2 be fixed. I can check. There's nothing -- the documents
3 are all correct, just the header was wrong.

4 JUDGE WALLACE: Ms. Hayden, do you want
5 to take a couple minutes look these over?

6 MS. HAYDEN: If I could, please, your
7 Honor. Thank you.

8 JUDGE WALLACE: Off the record.

9 (Off-record from 4:03 p.m. until 4:06 p.m.)

10 JUDGE WALLACE: All right. Is there any
11 objection to the admission of Exhibits MEC-28 through 35
12 and MEC-38?

13 Hearing none, those exhibits are
14 admitted.

15 Oh, did we go back on the record?

16 COURT REPORTER: I went back on the
17 record.

18 JUDGE WALLACE: Thank you for that. So
19 Ms. Hayden, do you need some time to confer with
20 Mr. Kryscynski in terms of redirect?

21 MS. HAYDEN: Yes, I do.

22 JUDGE WALLACE: Ms. Andrews, you're done
23 with this witness, correct?

24 MS. ANDREWS: Yes, your Honor. Thank
25 you.

1 JUDGE WALLACE: O.K. Do you want a
2 couple minutes to decide if you need to do any redirect?

3 MS. HAYDEN: If we could take 15 minutes.
4 Appreciate that.

5 JUDGE WALLACE: Fifteen minutes, yeah.

6 MS. HAYDEN: Thank you.

7 (Recess from 4:07 p.m. until 4:26 p.m.)

8 JUDGE WALLACE: I forgot to ask before,
9 does anyone else have any questions for Mr. Kryscynski?
10 (No response.)

11 All right. Ms. Hayden, do you need to do
12 any redirect?

13 MS. HAYDEN: I have some very short
14 redirect, your Honor.

15 JUDGE WALLACE: O.K. Please go ahead.

16 REDIRECT EXAMINATION

17 BY MS. HAYDEN:

18 Q My first topic is really to follow up on a question
19 Ms. Andrews asked earlier in the cross-examination.
20 Referring to the GPM model, the workpaper exhibit, we had
21 been discussing the tab, the GPM results tab and the two
22 different tables within the GPM results tab. Looking
23 specifically at line 13, column AW --

24 A Yes.

25 Q -- there was a question as to whether -- there was an
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1 observation that there is a score in row 13, column AW,
2 correct?

3 A Correct.

4 Q And also an observation that in column AY, the score for
5 ranking is -999. Do you recall that line of questioning?

6 A I do.

7 Q Can you explain why there would be a score in column AW
8 and a score for ranking of -999 in column AY?

9 A Yes. There are certain projects we exclude from the
10 ranking table on the left-hand side of the page, the far
11 left-hand side, and they can be excluded for generally
12 one of three reasons: One is that they are driven
13 primarily by benefits that are not captured in the GPM;
14 the other, another reason would be that they're pilot or
15 NWA projects that are, that are kind of already
16 preselected through other methods; and then the last is a
17 project or program for this run of the GPM would have a,
18 due to the project schedule, you know, potentially
19 design, would not have investment until years outside of
20 the rate case window, so, you know, typically '26 through
21 '27, '28.

22 Q Thank you. Just for clarity, can you define NWA?

23 A Non-wire alternative.

24 Q Separately, there was also some discussion of the
25 reliability model, in particular, the benefits walkdown

1 and degradation tab.

2 A Yes.

3 Q Was there an error that you identified during the break
4 on that tab?

5 A Yes. For, if we look at that tab, row 3, when it said
6 the PTMM pre-2023/enhanced specs, it should be pre-2022/
7 enhanced specs. And so when Ms. Andrews had asked me
8 earlier whether if a PTMM year of 2022 would have zero
9 benefit and used this table, I indicated it would,
10 whereas in fact a 20, year of 2022 is actually uses the
11 table below and does receive a benefit, and the table
12 below in row, it starts in row 114.

13 Q O.K. Just for clarity, I think you said the initial
14 table (inaudible) --

15 COURT REPORTER: I'm sorry. The initial
16 table?

17 Q (By Ms. Hayden): -- starts in row 3, but it looks like
18 it actually, the line item you're referring to is row 4?

19 A The one I'm looking at, the error is at row 3, where it
20 says PTMM pre-2023, it should say pre-2024. Is that what
21 you're seeing?

22 Q Looks like we have some different models.

23 A Which I'm using the workpaper one.

24 Q That may be the difference. Apology.

25 A Either way, whether 3 or 4, it should say pre-2022

1 instead of pre-2023.

2 MS. HAYDEN: Thank you. That's all I
3 have.

4 JUDGE WALLACE: Any recross, Ms. Andrews?

5 MS. ANDREWS: Yes.

6 REXCROSS-EXAMINATION

7 BY MS. ANDREWS:

8 Q Going back to the first point that you made regarding the
9 GPM model, in particular the GPM results tab, I think you
10 were talking about line 13, column AW, and you identified
11 three reasons that a project might be excluded even
12 though it has a score. Can you clarify which, what the
13 case was in particular with the disconnect and disconnect
14 and switcher replacement project that is referred to in
15 that line?

16 A That is, that program is excluded because of the benefits
17 are primarily outside of the reliability model.

18 Q Can you extrapolate?

19 A Sorry, I misspoke. Outside of the GPM model
20 (inaudible) --

21 (Multiple speakers.)

22 COURT REPORTER: Outside of the -- wait a
23 minute. You starting talking over him. Outside of the
24 GPM model?

25 A Yes. The benefits are benefits of this project, that we
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1 get from this project, the Company gets from this project
2 are typically not found or not scored in the GPM model.

3 Q (By Ms. Andrews): And what are those benefits?

4 A I would direct you to I believe this is -- I apologize,
5 I'm not sure if this is Witness Deol or Witness Elliott
6 Andahazy who covers this program; they cover it, they
7 cover the benefits. I'd also direct to you the capital
8 summaries, which would have that.

9 Q So the program is proceeding, it's just proceeding
10 outside of the GPM?

11 A The program is proceeding because it has benefits that
12 are not captured in the GPM.

13 Q And just to clarify, as I understand it, related to the
14 reliability model, a circuit that was, that received PTMM
15 intervention or treatment in 2021 would get zero
16 continuing benefits in the model, correct?

17 A That is correct.

18 Q Whereas a PTMM treated circuit that received benefits in
19 2022, starting in 2022, that would be year zero, so it
20 would get half the benefits shown in the reliability
21 benefits walkdown tab?

22 A That is correct.

23 MS. ANDREWS: O.K. I have no further
24 questions.

25 JUDGE WALLACE: All right. Thank you
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1 very much, Mr. Kryscynski. You are excused.

2 (The witness was excused.)

3 - - -

4 JUDGE WALLACE: Ms. Andrews, you
5 indicated you have some exhibits that you would like to
6 have admitted in lieu of cross-examination of
7 Ms. Steudle.

8 MS. ANDREWS: That's right. We had
9 reserved, I had reserved an hour of cross-examination, it
10 partly had to do with subject matter. I do have two
11 exhibits, they are loaded in the SharePoint folder, they
12 are labeled as Exhibit MEC-69 and 70, and I'm willing to
13 pass the witness and have those exhibits admitted in lieu
14 of calling her to identify and discuss them or otherwise.

15 JUDGE WALLACE: Ms. Hayden, have you had
16 an opportunity to review the two exhibits?

17 MS. HAYDEN: I am doing so right now,
18 your Honor. I just need two minutes.

19 (Brief pause.)

20 No objection from the Company on those
21 exhibits.

22 JUDGE WALLACE: All right. Is there any
23 objection from anybody else concerning the admission of
24 Exhibits MEC-69 and MEC-70?

25 Hearing none, those exhibits are
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1 admitted.

2 MS. ANDREWS: Thank you, your Honor.

3 JUDGE WALLACE: O.K. Let's go off the
4 record for just a second.

5 (Off-record discussion, 4:37 p.m. until 4:51 p.m.)

6 JUDGE WALLACE: Well, just to be clear
7 for the record, I will ask to have a separate Teams
8 meeting room set up for confidential cross tomorrow and
9 Monday. It will be a very limited group of people who
10 will be permitted in to that confidential session, and
11 we'll, hopefully the Company maybe have somebody there
12 that's got the list so we make sure that whose ever in
13 that room. While, I won't forward it to anyone who's not
14 on that list, I can't keep them from forwarding it to
15 other people, so we still need to sort of keep track of
16 the list. So anyway.

17 All right. Then I guess that's it for
18 today. And thank you, all, very much, and I will see you
19 tomorrow morning. And we are off the record.

20 (At 4:52 p.m., the hearing was adjourned to Friday,
21 September 6, 2024.)

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C E R T I F I C A T E

I, Lori Anne Penn (CSR-1315), do hereby certify that I reported in stenotype via Microsoft Teams the proceedings had in the above-entitled matter, that being Case No. U-21534, before Sally L. Wallace, J.D., Administrative Law Judge with Michigan Office of Administrative Hearings and Rules, for the Michigan Public Service Commission, Lansing, Michigan, on Thursday, September 5, 2024; and do further certify that the foregoing transcript, consisting of Volume 3, pages 279-612, constitutes a true and correct transcript of my stenotype notes.

Lori Anne Penn

Lori Anne Penn, CSR-1315
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Dated: September 6, 2024