

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of
DTE Electric Company to increase its
rates, amend its rate schedules and
rules governing the distribution and
supply of electric energy, and for
miscellaneous accounting authority.

Case No. U-21534

Volume No. 5

PUBLIC RECORD

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
Monday, September 9, 2024, at 9:12 a.m.

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Monday, September 9, 2024

At 9:12 a.m.

- - -

(Hearing resumes following adjournment of Friday,
September 6, 2024.)

JUDGE WALLACE: All right. We are back on the record in Case No. U-21534, In the matter of the application of DTE Electric for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply electric energy, and for miscellaneous accounting authority. I am Sally Wallace, and I'm the ALJ who's been assigned to preside over the hearings in this matter. The Commission will be reading the record.

To begin with today, I'm going to go ahead and take appearances, beginning with you Ms. Johnson-Bacon.

MS. JOHNSON-BACON: Good morning, your Honor. Paula Johnson-Bacon appearing on behalf of DTE Electric Company. Also appearing with me today on behalf of the Company is Jon Christinidis.

JUDGE WALLACE: Good morning.
Ms. Durian.

MS. DURIAN: Good morning, your Honor.
Heather Durian on behalf of the Michigan Public Service
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1 Commission Staff. Also entering the appearances of Amit
2 Singh, Monica Stephens, and Michael Orris.

3 JUDGE WALLACE: Good morning, Ms. Durian.
4 Mr. King.

5 MR. KING: Good morning, your Honor.
6 Joel King appearing this morning on behalf of Attorney
7 General Dana Nessel.

8 JUDGE WALLACE: Good morning, Mr. King.
9 Mr. Bzdok.

10 MR. BZDOK: Good morning, your Honor.
11 Christopher Bzdok along with Tracy J., T.J. Andrews on
12 behalf of the Michigan Environmental Council, Natural
13 Resources Defense Council, Sierra Club, and Citizens
14 Utility Board of Michigan.

15 JUDGE WALLACE: Good morning.
16 Mr. Abrams.

17 MR. ABRAMS: Good morning, your Honor,
18 Daniel Abrams appearing on behalf of the Ecology Center,
19 the Environmental Law & Policy Center, the Union of
20 Concerned Scientists, and Vote Solar, collectively the
21 Clean Energy Organizations.

22 JUDGE WALLACE: Good morning, Mr. Abrams.
23 Mr. Boehm.

24 MR. BOEHM: Good morning, your Honor.
25 Kurt Boehm appearing on behalf of The Kroger Company.

1 JUDGE WALLACE: Good morning.

2 Ms. Brader.

3 MS. BRADER: Good morning, your Honor.

4 Valerie Brader appearing on behalf of the City of Ann
5 Arbor and the Michigan Municipal Association for Utility
6 Issues.

7 JUDGE WALLACE: Good morning, Ms. Brader.

8 Mr. Templeton.

9 MR. TEMPLETON: Good morning, your Honor.

10 Mark Templeton of the Abrams Environmental Law Clinic
11 appearing on behalf of Soulardarity and We Want Green,
12 Too, collectively known as the Detroit Area Advocacy
13 Organizations in this proceeding. Also entering an
14 appearance on behalf of my colleague Jacob Schuhardt.

15 JUDGE WALLACE: Good morning,

16 Mr. Templeton. Ms. Horne.

17 MS. HORNE: Good morning. Your Honor.

18 Melissa Horne on behalf of Walmart, Inc.

19 JUDGE WALLACE: Good morning, Ms. Horne.

20 Mr. Vijaykar. Are you there, Mr. Vijaykar? Maybe you're
21 muted. You were here a minute ago.

22 O.K. Ms. Flower.

23 MS. FLOWER: Good morning, your Honor.

24 Olivia Flower here representing ITC Transmission, and
25 also entering appearances on behalf of my colleagues,

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1 Rick Aaron and Hannah Buzolits and Courtney Kissell.

2 JUDGE WALLACE: Good morning, Ms. Flower.
3 Mr. Bright.

4 MR. BRIGHT: Good morning, your Honor.
5 Stephen Bright on behalf of Electrify America, LLC.

6 JUDGE WALLACE: Good morning, Mr. Bright.
7 Did I miss anyone? (No response.)

8 All right. As we discussed before we
9 went on the record, we're going to start with
10 cross-examination of Mr. Deol with a hard break scheduled
11 at five till 10:00. We will be in confidential cross a
12 couple of times, and last week we set up a separate Teams
13 meeting for confidential cross-examination, so when it's
14 time to go in, we all leave this meeting, go into the
15 other meeting that is confidential, and the Company will
16 confirm that the people who are in that session do have
17 the proper NDA signed. There's two different NDAs, one
18 for CEII, Critical Electric Infrastructure something,
19 Information maybe, and the other one which is just for
20 regular confidential or proprietary information. So
21 think that we're good to go forward.

22 So Ms. Johnson-Bacon, please call your
23 witness.

24 MS. JOHNSON-BACON: The Company calls
25 Satvir S. Deol. Ms. Penn, would you swear the witness,
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1 please.

2 - - -

3 S A T V I R R. D E O L

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 JUDGE WALLACE:

9 Q Mr. Deol, could you please state your name for the
10 record?

11 A Yes. Good morning. I'm Satvir Deol.

12 Q And your business address?

13 A It's One Energy Plaza, Detroit, Michigan 48226.

14 Q Did you file with the Commission a document entitled the
15 Qualifications and Direct Testimony of Satvir S. Deol,
16 consisting of a cover page and 88 pages of questions and
17 answers?

18 A Yes.

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

21 A Yes, I do.

22 Q And what are those changes?

23 A On page 33, Footnote 2, instead of "Chapter 21", it
24 should read "Chapter 12". And then on page 51, line 8,
25 instead of "circuits", the testimony should state

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1 "circuit miles".

2 Q Is that, then, the direct testimony that you're adopting
3 today?

4 A Yes.

5 Q Are you sponsoring any exhibits associated with your
6 direct testimony in this case?

7 A Yes, I am.

8 Q For purposes of identification, are these five direct
9 exhibits designated as A-12 Schedule B5.4, consisting of
10 26 pages; Exhibit A-23 Schedule M6, consisting of 404
11 pages; Exhibit A-23 Schedule M11, consisting of 10 pages;
12 and Exhibit A-23 Schedule M13, consisting of 236 pages;
13 and A-28 Schedule R1, consisting of one page?

14 A Yes, I did.

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

16 A Yes, they were.

17 Q Do you have any changes that you need to make to any of
18 these direct exhibits?

19 A No.

20 Q Did you also file with the Commission a document entitled
21 the Rebuttal Testimony of Satvir S. Deol, consisting of a
22 cover sheet and 51 pages of questions and answers?

23 A Yes, I did.

24 Q Do you have any changes you wish to make to your rebuttal
25 testimony?

1 A Yes. On page 26, line 17, instead of "circuits", it
2 should read "circuit miles".

3 Q Is that, then, the rebuttal testimony that you're
4 adopting today?

5 A Yes.

6 Q Are you sponsoring any exhibits associated with your
7 rebuttal testimony in this case?

8 A Yes, I am.

9 Q For purposes of identification, are these three rebuttal
10 exhibits designated as Exhibit A-50 Schedule 001,
11 consisting of two pages; Confidential CEII Protected
12 Exhibit 50 Schedule 002, consisting of four pages; and
13 Exhibit A-50 Schedule 003, consisting of six pages?

14 A Yes.

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

16 A Yes, they were.

17 Q Do you have any changes to make to any of these rebuttal
18 exhibits?

19 A No, I don't.

20 MS. JOHNSON-BACON: Your Honor, DTE
21 Electric moves to bind into the record the
22 Qualifications, Direct Testimony, and Rebuttal Testimony
23 of Satvir S. Deol, as well as the aforementioned
24 exhibits, and tenders Mr. Deol for cross-examination.

25 JUDGE WALLACE: Thank you,
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1 Ms. Johnson-Bacon. Is there any objection to binding in
2 the revised direct testimony, with the changes in that
3 testimony that are indicated on the record here?

4 Hearing none, the revised direct
5 testimony of Mr. Deol is bound into the record.

6 Is there any objection to binding in the
7 revised rebuttal testimony and, again, those revisions
8 are indicated here on the record, of Mr., the revised
9 rebuttal testimony of Mr. Deol?

10 Hearing none, the testimony is admitted.

11 (Testimony bound in.)

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STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

QUALIFICATIONS

AND

REVISED DIRECT TESTIMONY

OF

SATVIR S. DEOL

DTE ELECTRIC COMPANY**QUALIFICATIONS AND REVISED DIRECT TESTIMONY OF SATVIR S. DEOL**Line
No.

1 **Q1. What is your name, business address and by whom are you employed?**

2 A1. My name is Satvir S. Deol (he/him/his), and my business address is One Energy
3 Plaza, Detroit, Michigan, 48226 and I am employed by DTE Electric Company
4 (DTE Electric or Company).

5

6 **Q2. On whose behalf are you testifying?**

7 A2. I am testifying on behalf of DTE Electric.

8

9 **Q3. What is your educational background?**

10 A3. I received a Bachelor of Science Degree in Electrical Engineering specializing in
11 Power Distribution from Michigan Technological University. I graduated from the
12 University of Minnesota with a Master of Science in Electrical Engineering
13 specializing in Power System Control. I also have a Master of Business
14 Administration specializing in Finance from University of Michigan, Dearborn.
15 Furthermore, I have attended professional development courses in power system
16 design & protection and circuit modeling & power flow analysis. I was also trained
17 in the Toyota Production System (TPS) continuous improvement methodologies.

18

19 **Q4. Please summarize your professional experience.**

20 A4. I worked for Shell Western Exploration & Production, Inc. (SWEPI) as a facilities
21 engineer from 1990 to 1992. I was responsible for coordinating & performing
22 maintenance on substations, co-generation facilities, and the power distribution
23 network for all oil production fields and offshore platforms in California. I also
24 supported the field electrical teams for emergent issues and was the project manager
25 for several major electrical projects. I worked for Ford Motor Company (Ford)

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

13
14 I joined DTE Energy in 2007 as a program manager to implement continuous
15 improvement programs within the Materials & Logistics organization. After a
16 series of roles with increasing responsibility, in 2010 I was promoted to senior
17 supply chain manager supporting Fossil Generation Operations.

18
19 In 2013, I moved to Distribution Operations as a program leader for a continuous
20 improvement project focusing on the oil distribution breaker inspection process. In
21 2014, I assumed the role as a service center manager leading the Southwest region
22 for Substation Operations. In this role, I was responsible for the operation, planned
23 and corrective maintenance, and executing capital projects for substations. I was
24 given the additional responsibility of the Southeast region in 2016. In 2018, I was
25 promoted to director of Substation Operations.

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1 As director of Substation Operations, I was responsible for safe and reliable
2 operation of all the substations within the DTE Electric service territory. The major
3 areas of focus were: 1) safety, 2) planned maintenance, 3) emergent and corrective
4 maintenance, 4) capital replacement programs, and 5) continuous improvement.
5 In 2023, I assumed the role of director of Central Engineering.

6

7 **Q5. Do you hold any certifications or are you a member of any professional**
8 **organizations?**

9 A5. I am a Lean Six Sigma Blackbelt.

10

11 **Q6. What are your current duties and responsibilities?**

12 A6. As director of Central Engineering, I lead the Central Engineering organization that
13 is responsible for determining the health of the Company's electric distribution
14 assets and developing projects and programs to maintain and improve their safe,
15 reliable, and cost-effective operation. I oversee Central Engineering activities,
16 which include defining technical standards for the equipment to be utilized on the
17 distribution system, long-term system planning including grid modernization, and
18 developing major projects needed for customer connections, relocations, increasing
19 loads, infrastructure improvements, reliability upgrades, and technology
20 enhancements.

21

22 **Q7. Have you previously sponsored testimony before the Michigan Public Service**
23 **Commission (MPSC or Commission)?**

24 A7. Yes. I sponsored testimony in the following DTE Electric cases:

25 U-21297 DTE Electric 2023 Rate Case

Line
No.

1 **Purpose of Testimony**

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

3 A8. As referenced in witness Kryscynski's description of the Distribution Operations
4 organization, the purpose of my testimony is to support, as reasonable and prudent,
5 the historical capital expenditures for 2022 and projected capital expenditures for
6 2023 through December 31, 2025, in the distribution strategic investment category
7 of Infrastructure Redesign and Modernization and the programs associated with the
8 Company's Infrastructure Recovery Mechanism (IRM).

9

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

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

12	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
13	A-12	B5.4	Projected Capital Expenditures – Distribution Plan
14			(Pages 1, 2, 14-16, and 19-26)
15	A-23	M6	Distribution Plant Capital Project Detail –
16			Infrastructure Redesign and Modernization
17	A-23	M11	Appoline Report
18	A-23	M13	Benefit Cost Analysis Whitepaper
19	A-28	R1	Buffalo Charles Letter of Support

20

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

22 A10. Yes, they were.

23

24 **Q11. How is your testimony organized?**

25 A11. My testimony consists of the following parts:

Line
No.

1 Part I Infrastructure Recovery Mechanism (IRM) Support

2 Part II Infrastructure Redesign and Modernization

3

4 **Part I Infrastructure Recovery Mechanism (IRM) Support**

5 **Q12. Are any of the programs you are supporting impacted by the Company's**
6 **Distribution Infrastructure Recovery Mechanism (Distribution IRM or**
7 **IRM)?**

8 A12. Yes, as described by Company Witness Foley in his testimony, in its December 1,
9 2023 Order in Case No. U-21297 (December 2023 Order), the Commission
10 authorized IRM treatment for the Conversion projects (4.8kV Conversion and
11 Consolidation (CC), 4.8kV ISO Conversion, 8.3kV CC, and City of Detroit
12 Infrastructure (CODI)), and the Subtransmission Redesign & Rebuild program
13 from December 1, 2023 through the end of 2025.

14

15 **Q13. Is the Company proposing any additional investment in these programs**
16 **during the bridge and/or test years beyond what the Commission previously**
17 **authorized for recovery through the IRM?**

18 A13. Yes, as reflected in Exhibit A-12, Schedule B5.4, the Company is proposing
19 additional Conversions and Subtransmission Redesign & Rebuild investment
20 during the bridge and test years of this case. Additional Conversions program
21 investment is captured on Page 14 (Lines 28-36), Page 15 (Lines 37-56), and Page
22 16 (Lines 79-91). Additional Subtransmission Redesign & Rebuild program
23 investment is captured on Page 14 (Lines 5-27) and Page 15 (Lines 66-78). This
24 investment is incremental to the investment already authorized for IRM treatment

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1 during these years and will support different work to avoid double recovery of the
2 same investment.

3

4 **Q14. Is the Company proposing recovery for any additional investment in these**
5 **programs through the IRM beyond the test year of this case?**

6 A14. Yes, as described by Company Witness Foley, the Company is proposing a two-
7 year extension of the IRM (i.e., calendar years 2026 and 2027). As part of that
8 extension the Company is proposing recovery of additional Conversions and
9 Subtransmission Redesign & Rebuild capital investment as captured in Exhibit A-
10 33, Schedule X1.

11

12 **Part II: The Infrastructure Redesign and Modernization Pillar**

13 **Q15. Can you describe the Company's Infrastructure Redesign and Modernization**
14 **Pillar?**

15 A15. The Infrastructure Redesign and Modernization Pillar focuses on fundamentally
16 rebuilding and modernizing the near century old grid to support the long-term grid
17 needs. The specific investments in this pillar are essential to meeting the evolving
18 needs of customers, including adoption of electric vehicles (EVs) and other forms
19 of electrification, distributed energy resources (DER), and the evolving ways in
20 which customers are interacting with the grid.

21

22 The goals of the projects and investments in this pillar are to add capacity and
23 operational technology, while hardening the grid to enhance safety, reliability, and
24 resiliency. These projects include elimination of loading constraints, redesign and

Line
No.

1 rebuild of the subtransmission system to provide operational redundancy and
2 address lack of capacity on significant portions of the Company's grid.

3

4 **Q16. What grid investment areas are included in the Infrastructure Redesign and**
5 **Modernization Pillar?**

6 A16. Infrastructure Redesign and Modernization investments focus on the distribution
7 and subtransmission segments of the grid.

8

9 The distribution system is designed to distribute electricity from a substation to the
10 customers. The Company's current distribution system has voltages of 4.8 kV, 8.3
11 kV, and 13.2 kV. In analyzing the long-term grid needs and to address the current
12 challenges of the 4.8 kV and 8.3 kV circuits, the Company plans to convert all 4.8
13 kV and 8.3 kV grid infrastructure to a higher voltage over time.

14

15 The Company's Conversion Program investments focus of converting the 4.8 kV
16 and 8.3 kV circuits to a higher voltage. With evolving climate change, the
17 Company is experiencing an increased number of severe weather events of greater
18 frequency and severity. Weather impacts, aged electrical infrastructure, and the
19 need to support current and future load growth require a higher voltage, harden, and
20 resilient grid.

21

22 The distribution system is also addressed by the System Loading project
23 investments. These projects focus on relieving system overloads, improving
24 reliability, and adding capacity predominantly on the 13.2 kV distribution system.

25

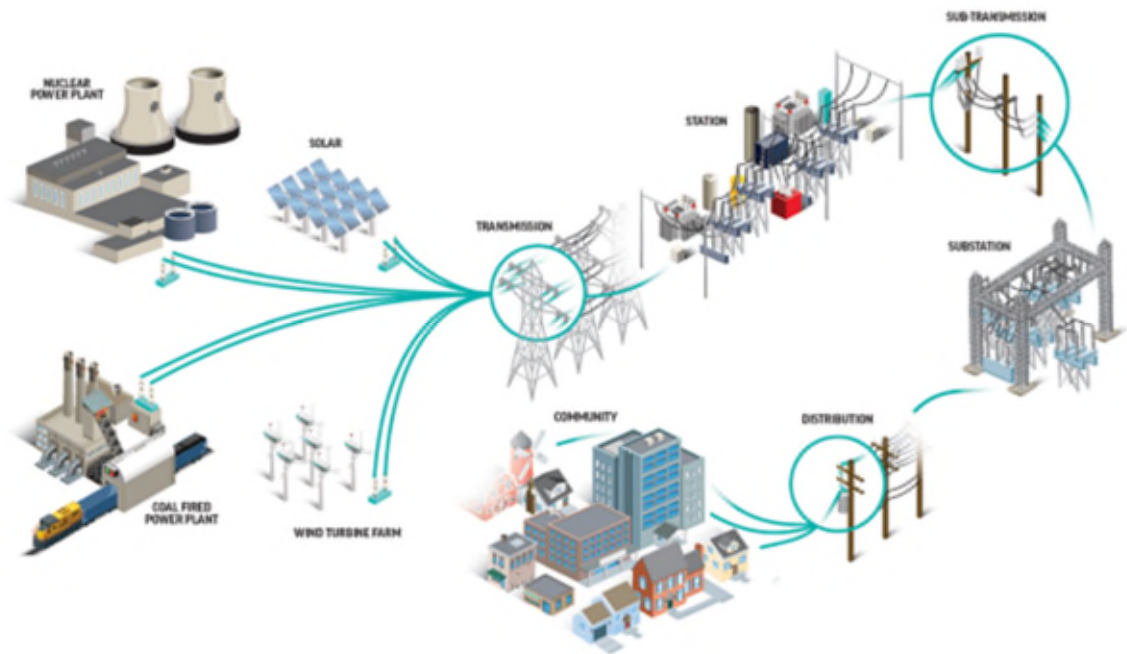
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1 The subtransmission system consists of the infrastructure that provides higher
2 voltage into substations that then convert the higher voltage to lower-level
3 distribution voltages (4.8 kV, 8.3 kV, and 13.2 kV). The Company's
4 subtransmission system has voltages of 24 kV, 40 kV, and 120 kV.

5
6 The Company's Subtransmission Redesign & Rebuild program investments focus
7 on this critical upstream feed to the distribution system. These projects focus on
8 improving the reliability, redundancy, and capacity of the subtransmission system.

9
10 Figure 1 below illustrates the difference between the distribution and
11 subtransmission system.

12
13 **Figure 1 Electrical Distribution System Overview**



Line
No.

1 Summary level Capital investment details for Infrastructure Redesign and
2 Modernization projects are provided in Exhibit A-12, Schedule B5.4, pages 14-16
3 and Exhibit A-23, Schedule M6. Also included in Exhibit A-12, Schedule B5.4 for
4 this category is AFUDC on page 19 and plant activity on pages 20-26, described in
5 more detail by Company Witness Kryscynski.

6

7 **Q17. Can you discuss in more detail the Infrastructure Redesign and Modernization**
8 **programs?**

9 A17. I would like to expand on these programs because I believe that will be helpful in
10 establishing a deeper understanding of their key objectives, scope, the rationale for
11 making the investments, and the benefits customers will receive.

- 12 • Conversion Programs
 - 13 o 4.8 kV Conversion
 - 14 o City of Detroit Infrastructure (CODI)
 - 15 o 4.8 kV ISO Conversion
 - 16 o 8.3 kV CC Pontiac Conversion
- 17 • Subtransmission Redesign & Rebuild
- 18 • Strategic Undergrounding Projects
- 19 • Primary Deconductoring
- 20 • System Loading

21

22 Conversion Programs

23 4.8 kV Conversion

24

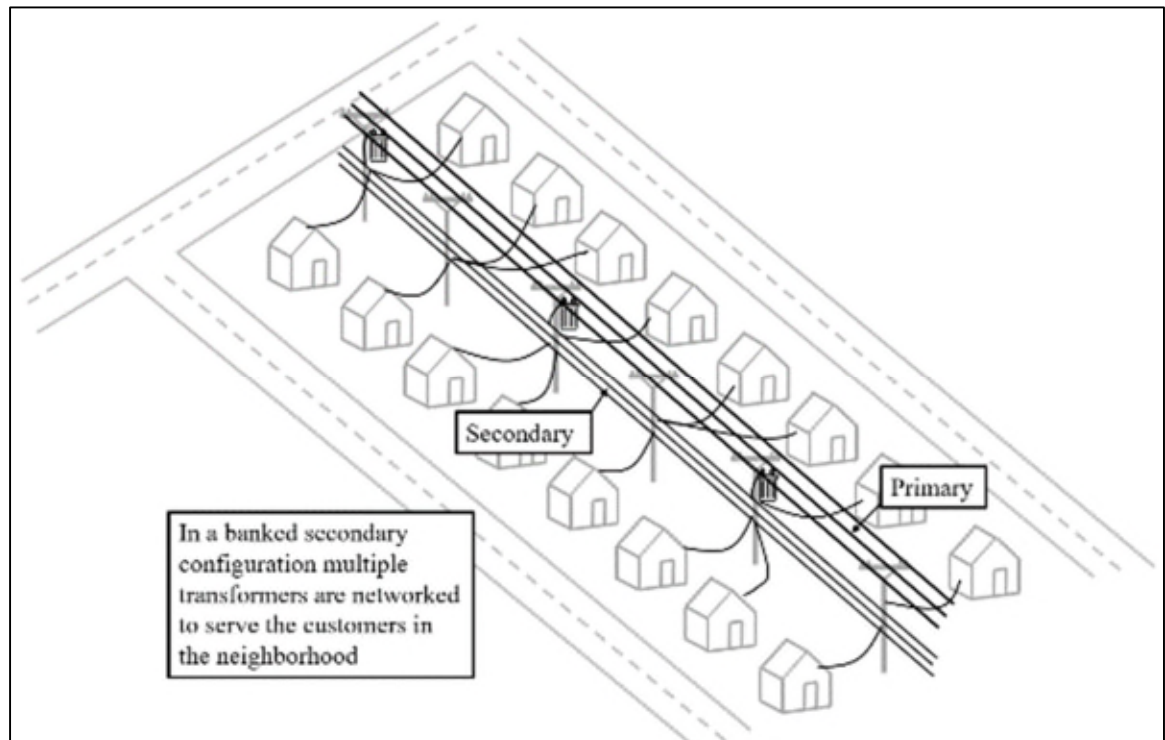
25 **Q18. Can you describe the Company's 4.8 kV distribution system?**

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1 A18. The Company's original distribution system voltage is 4.8 kV. The system was
2 designed nearly a century ago with standards of the time that included an
3 ungrounded delta configuration with banked secondary. For an ungrounded delta
4 configuration protective trip device to operate on the system, two of the high-power
5 lines need to contact each other or ground. Thus, a single downed wire is
6 challenging for the protective devices to detect in a delta configuration. A banked
7 secondary configuration has multiple transformers interconnected to provide power
8 to a local area of customers. Figure 2 below shows a banked secondary
9 configuration.

Figure 2 Banked Secondary Configuration

13 The 4.8 kV delta configuration coupled with the banked secondary is a design from
14 the early 1900's, which for many decades provided good reliability with a low



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1 number of outages for the Company's customers. Currently, the 4.8 kV delta
2 system has many challenges which include safety, reduced distribution capacity,
3 and degrading reliability due to its age.

4

5 **Q19. Can you describe in more detail the challenges and issues associated with the**
6 **4.8 kV system?**

7 A19. Improving safety risk associated from downed wires on the current 4.8 kV
8 ungrounded delta circuits is a major focus of the conversion program. It is more
9 susceptible to wire-downs due to small #6 and #4 copper conductors, which are
10 weaker in strength compared to current higher standard wires, and in many cases
11 have deteriorated and weakened by age and the annealing effects of thermal
12 cycling. Due to the ungrounded configuration of the 4.8kV delta system, a downed
13 wire can potentially remain energized until mitigated by the Company's workforce.

14

15 Capacity is limited due to the inherently lower rating of equipment at 4.8 kV,
16 including, but not limited to, substation transformers and conductor or cable sizes.
17 On many circuits, this impacts the Company's ability to connect new customers or
18 facilitate growth of existing customers.

19

20 Reliability of the 4.8 kV system, both in terms of outages (frequency and duration)
21 and power quality, impacts the customer experience. When originally constructed,
22 the 4.8kV system was modern, accessible, and reliable for a customer base with a
23 much lower electrical demand. Driven by a combination of the age of the system,
24 inaccessibility of infrastructure, and changing customer demands, the 4.8 kV
25 system is no longer a reliable design choice.

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In addition to the lower reliability and capacity constraints of the 4.8kV system, it also limits the operability for the Company. Smaller wire sizes and lower circuit/substation ratings limit the ability to reconfigure the system to restore customers in adjacent areas during planned or unplanned outages. This can result in larger area and longer duration outage events for the Company's customers.

7

8

Accessibility is another major challenge of the 4.8 kV system. In most neighborhoods, the 4.8 kV system was constructed as overhead rear-lot poles and wires, which customers find aesthetically preferable to front-lot construction. Initially, right-of-way truck access was readily available through municipally maintained alleys in many areas, including much of Detroit. Starting in the mid-1950's, many municipalities began abandoning the alleys and allowed property owners to extend their fence lines, inhibiting Company truck access to the poles and wires. Consequently, the limited access results in extended time to locate and repair trouble on the 4.8 kV system, as well as increases in time to perform tree trimming and other maintenance work.

18

19

Other key challenges impacting the Company's 4.8 kV system are:

20

- The 4.8 kV system can experience more significant voltage drops than higher voltage systems.

21

22

- Ringed circuit and banked secondary designs make maintenance, fault identification, troubleshooting, and restoration more difficult and therefore can result in outages that are longer in duration.

23

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- 1 • The 4.8 kV system is less able to incorporate current technology automation
2 standards because it has a limited amount of remote monitoring and control
3 capability when compared to higher grid voltages. Due to inherent space
4 limitations and equipment age, the retrofits on 4.8 kV substations to enhance
5 remote monitoring and control capability are more costly and challenging.
6 For example, the original 4.8 kV substation design included individual relays
7 for individual functions, usually installed on a 3-foot-by-7-foot granite
8 panel. When a new breaker is installed these granite panels are removed and
9 a new prewired relay panel with current technology is installed. Even though
10 the new prewired panel reduces installation time at the substation, all the
11 new control wires still must be installed from the panel to the breaker, which
12 is time consuming, and costly.

13

14 **Q20. Why does the Company plan to convert its 4.8 kV system?**

15 A20. As described earlier, the 4.8 kV system has many challenges related to safety,
16 capacity, reliability, operability, and accessibility, and this negatively impacts the
17 customers served by the 4.8 kV system. In analyzing the long-term grid needs and
18 to address the current challenges of the 4.8 kV system, the Company has determined
19 that a higher grid voltage system is required. The conversion program will build
20 new, modern, higher voltage substations. The newly constructed higher voltage
21 distribution circuits will be built to the current construction standards that will
22 harden the grid and implement a higher level of automation. The conversion
23 program will improve safety by reducing wire-down events. Converting to a higher
24 system voltage will add capacity to support new and growing customer load, and
25 better support new electrification technologies and DERs. The hardened circuits

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1 will improve reliability, operability, and reduce emergent maintenance costs.
2 Automation will allow for remote operations to reduce the number of customers
3 impacted by outages and reduce restoration time by quickly identifying trouble
4 locations. The new circuits will be designed and built to improve accessibility by
5 relocating to be truck accessibility wherever possible allowing for quicker crew
6 response time.

7

8 Through the conversion program, the Company expects to see a reduction of up to
9 90% in customer minutes of interruption, wire downs, and trouble events.

10

11 **Q21. What is the scope of the 4.8 kV Conversion program?**

12 A21. The detailed scope of the 4.8 kV conversion program is as follows:

- 13 • Building new, higher voltage substations or in some cases expanding and
14 upgrading existing 13.2 kV substations. This will improve the ability to
15 connect new customers and allow for load growth for existing customers.
- 16 • Completing overhead pre-conversion work including rebuilding pole top
17 equipment, replacing poles, wires, and transformers as needed, and installing
18 neutral wire.
- 19 • Undergrounding of the overhead wires will also be evaluated for
20 construction feasibility, customer acceptance, and cost effectiveness.
- 21 • Reconfiguring circuits and establishing new jumpering points will be
22 completed to improve operability. Jumpering is used during outage
23 circumstances and is the act of feeding a circuit that has become deenergized
24 by connecting it to an adjacent circuit, thus restoring power to the customers
25 on the deenergized circuit.

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- 1 • Converting and transferring the load from the 4.8 kV substations to the 13.2
- 2 kV substations.
- 3 • Installing controls and automation in the substations and circuits to current
- 4 design standards.
- 5 • Remove arc wire and Detroit Public Light Department primary from the
- 6 Company's system, on applicable Detroit circuits.
- 7 • Decommissioning of aging 4.8 kV substations and associated
- 8 subtransmission infrastructure.

9

10 **Q22. Do customers benefit from overhead pre-conversion work when it is**
 11 **constructed prior to building a new higher voltage substation or in parallel**
 12 **with substation construction?**

13 A22. Yes. In projects where overhead pre-conversion work is performed early or in
 14 parallel with the substation construction, the customers will see the reliability
 15 benefits sooner, even though upgraded equipment will continue to operate at 4.8
 16 kV until the area is ready for conversion. Upgraded pole-tops and wires deliver
 17 reliability improvements by a reduction in wire downs. Once the substation is
 18 subsequently built, the additional capacity benefits will be achieved as the circuits
 19 are converted to the higher voltage.

20

21 **Q23. How are conversion projects prioritized?**

22 A23. The Company's engineers develop conversion projects based on substation firm
 23 rating, circuit overloads, wire downs per OH mile, and substation risk. Consistent
 24 with other strategic projects and programs, conversion projects are prioritized using
 25 the Global Prioritization Model (GPM), which was updated in the 2023 DGP and

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is discussed in detail by Witness Kryscynski. A conversion project's GPM score is primarily impacted by the projects ability to address substation firm rating, circuit overloads, wire downs per OH mile, and substation risk plus the reliability improvement benefits and investments in Energy Justice (EJ) communities. More detail is provided in Exhibit A-23 Schedule M8 DGP, section 9.3.4 Prioritization of Conversion Projects.

Q24. What are the 4.8 kV Conversion projects included in this case?

A24. Table 1 below provides the high-level summary of the 4.8 kV Conversion projects included in this case. Detailed information for each of these projects is provided in exhibit A-23 schedule M6.

Table 1 Conversion Projects

Project Name	Municipality	Drivers
Cortland/ Oakman/ Linwood Consolidation	Detroit	Reliability & Operation: This project is part of a larger program to reduce 4.8kV breaker positions, transformers, and regulators. This will reduce O&M costs and provide spare components for equipment which is no longer manufactured. (LINWD SUB has 2 transformers, 2 regulators, and 11 breaker positions which are at or near end of life). This project will also eliminate associated underground cable
I-94 Substation and Circuit Conversion (Promenade)	Detroit	Safety: Significant assets are at high risk level including transformers, regulators, oil circuit breakers and disconnects. Along with 4.8kV and 24kV underground cable. Reliability: This area experiences wire down events which exceed the system average. Capacity: The Detroit Economic Growth Corporation has assembled the I-94 Industrial Park site – a 186-acre site north of I-94 between Mt. Elliott and Van Dyke on Detroit's east side. It is part of the 3,203-acre Mt. Elliot Development Zone, which is the single largest industrial district in Detroit and encompasses automotive, metal, transportation and logistics clusters. It offers access to major transportation assets. The site is a federally designated Historically Underutilized Business Zone and a state designated Renaissance Zone. Recent new loads were fed from the aging Lynch and Lambert 4.8 kV substations. The new substation is required to serve the load growth in and around I-94 industrial park and allows for decommissioning of the aging Lynch, Lambert, and Pulford 4.8 kV substations. Operability: Promenade will have loop schemes and jumpering points.
Almont Relief and Circuit Conversion (Midas OH) - DO	Village of Almont, Almont Township, Lapeer County, MI	Safety: 4.8kV causes a higher safety risk in an event of a wire-down. Each Almont circuit is ~55 OH line miles. Reliability: Almont substation was built in 1956 and there are no spare parts available for the breakers. Capacity: Almont 4.8kV substation is 132% of its firm rating. ALMOT DC 304 is 93% of the day-to-day rating of 5.1MVA and ALMOT DC 303 is 87% of the day-to-day rating of 4.8MVA. Both ALMOT circuits, DC 304 and DC 303, exceed the Distribution Design Order limit of 3MVA for a 4.8kV circuit. Five Method of Service requests have been received for new load on the substation but there is no capacity to serve these requests. Operability: There are little to no jumpering options available for Almont circuits because Almont is surrounded by 13.2kV circuits and substations. In 2019, a cable failure occurred causing a breaker failure and an extensive outage for the Almont area. Due to the high loads, the substation was blocked from automatic throwover.

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Table 1 Conversion Projects, Continued

Project Name	Municipality	Drivers
Buckler Circuit Conversion	Ann Arbor	Argo substation was built in 1926 and is a three transformer 4.8kV substation serving downtown Ann Arbor. Safety: 4.8kV Wire down elimination Capacity: The substation is currently unable to meet capacity needs in the rapidly growing downtown Ann Arbor area. The Argo circuits are limited to 3MVA based on the Distribution Design Order limit for a 4.8kV circuit. Argo substation is at 92% of its firm rating. The loading in this area will continue to increase which will eventually overload the substation and the circuits at Argo. Buckler substation was built to support current and future loads of Argo and the surrounding substations. Operability: Increased loading on 4.8kV circuits will inhibit the ability to transfer load.
McKinstry Sub Decommission	Detroit	McKinstry is a 24kV/4.8kV Class C substation. As part of the Gordie Howe Bridge Project, all of its circuits have been consolidated, converted and transferred to Zenon 120kV/13.2kV Class A substation. This specific project is to decommission McKinstry Substation, demolish the substation build and remove all associated equipment. Safety: 4.8kV causes a higher safety risk in the event of a wire down. Capacity: MCKNY has no load on the substation, all loads have been transferred elsewhere Other: Decommission (3) 24kV trunk lines. Decommission McKinstry Substation and demolish the building
Quincy Conversion	Yale	Safety: Power transformer sits on railroad ties instead of a transformer pad. Overhead stress from the leaning transformer causes safety concerns for those working on site. Other: QUNCY substation has low oil levels due to oil leaks, potentially causing future environmental impacts. QUNCY transformer is constructed on railroad ties that are rotten, causing the transformer to lean, adding stress to the overhead equipment.
Pinegrove Substation Relocation and Conversion (Neon)	Port Huron, St. Clair County, MI	Safety: 4.8kV causes a higher safety risk in the event of a wire down. Reliability: PINGV circuits were last trimmed in 2020. Capacity: PINGV substation is 72% of firm rating of 20.6 MVA. IMLAY0302 exceeds the 4.8kV DDO of day to day loading limits. Other: MDOT has requested the removal of the Pine Grove (PINGV) substation in Port Huron to facilitate the expansion of the Blue Water Bridge Plaza. PINGV substation is ~100 years old and is a 4.8kV substation located at the base of the Blue Water Bridge in Port Huron. The substation and its associated infrastructure support 16.3MVA of load for 5,340 customers on nine circuits. PINGV substation is not a standard configuration as it has high speed ground switches instead of a circuit switcher on the high side of the transformer. This project will decommission the aging 4.8kV PINGV substation and build a new 13.2kV NEON substation. Constructing a modern distribution system with a new 13.2kV substation and more robust infrastructure will improve reliability and provide options for future capacity expansion in the Port Huron area.
Hawthorne Relief and Circuit Conversion	Dearborn, Dearborn Heights, Detroit, Garden City, Livonia, Redford Township	Hawthorne substation area is a dense, 4.8 kV service territory with many commercial and residential customers. Adjacent substations are Daly, Biltmore, Villa, and Glendale. Safety: Higher frequency of 4.8kV wire-down events (3X higher than the DTE system average) Reliability: Aging 4.8kV infrastructure at GLEND (built in 1947), BLTMR(built in 1953), DALY (built in 1954), VILLA (built in 1961) and HAWTH (built in the 1950's) Capacity: Overloaded substations with very high %firms HAWTH(128%), VILLA (110%) and DALY (106%), Limited load capacity to accommodate projected load growth in the area Operability: Limited jumpering opportunities due to geography coupled with heavily loaded nearby circuits
Hawthorne Trf #2 and Secondary Cable Replacement	Dearborn Heights	Hawthorne Substation is located in and feeds very dense areas of Dearborn Heights. To improve the loadability at the substation, this project will replace 750VCL secondary bus cable from both transformers with larger 1500KCM cable. The existing Position "H" 1200A disconnect will also be upgraded to a 2000A disconnect. Safety: Larger cable allows for higher ampacity ratings, replaces an older cable, which means that the cable is less vulnerable to failure and other safety issues. Reliability: VCL cable is recognized as a high-risk cable in the DTE system. Capacity: Substation is at 129% of firm rating, limited by secondary cables Operability: Over firm condition limits ability to transfer load and maintain service.

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Table 1 Conversion Projects, Continued

Project Name	Municipality	Drivers
Crestwood Substation-Property	Dearborn	Other: Crestwood is an existing 120kV-13.2kV two transformer substation located in Dearborn, MI. The substation's property lease agreement expires in August of 2022. This request is to purchase this property from current land owner instead of extending the lease for another 49 years. Purchasing the property instead of extending the lease, would save approximately \$1,000,000.
MAUME 8241 Downtown Clawson Conversion	Clawson	Reliability: Multiple frequent outages in 2020 and 2021 impacting Downtown Clawson. Several customer/town hall meetings involve Clawson city government, as well as Clawson DDA.
Power Line Conversion MADSN175L - W	Detroit	Reliability & Operation: Work is necessary to convert MADSN LPL 175 L-W standard to Power Lines (PL) and remove PIL 175L-W due to pilot cable failure. Pilot wire circuit is unjacketed, leaded cable. Numerous attempts to repair the circuit have been unsuccessful; cable continues to fail hi-pot test
GRFIN & WMSTN 4.8 kV ISO Conversions	Webberville and Williamston, Ingham County	Safety: Circuits have long 4.8kV (ungrounded) overhead miles because of the large 4.8kV ISO down areas. Many outages occur during storms and many wires were laying on the ground from the tornado in summer 2023. Reliability: GRFIN9799, GRFIN9883, and WMSTN9856 are some of the largest circuits in DTE and have limited jumpering points because of numerous ISO-down transformers limiting capacity and small conductor sizes on backbone limiting capacity. Capacity: Multiple method of services (industrial customer requests) have been received on GRFIN9799. Customer load creates a circuit DDO violation on GRFIN9799 and substation firm violation on GRFIN as the firm is surpassed before a project is executed. Williamston (WMSTN) substation is adjacent to GRFIN substation and is below its firm rating with capacity available. WMSTN DC 9856 also has capacity available on it. Load can be cascaded from GRFIN DC 9799 to WMSTN DC 9856 to mitigate the DDO violation. To facilitate this load transfer, 4.8kV ISO down pockets on both circuits must be converted to 13.2kV operation. Operability: There are no jumpering options for either of the two circuits due to overloads and low voltage after jumpering. Jumpering points are limited because 4.8kV ISO down pockets are limiting jumpering, these circuits are bordering Consumer's Energy circuits, and there are small overhead line sizes for the circuits' backbone. Other: MOS QPS 1 was received in 2019 and MOS QPS 2 was received in 2021. The buildings are located in an open industrial zoned area with other industrial customers nearby and more industrial customers are expected in the future.
SCOTN Circuit Consolidation	Detroit	Safety: flooding in the Scotten (SCOTN) substation affected and condemned associated position breakers. After further investigation, the EPPM group at DTE concluded that all (36) position breakers will need to be replaced. The intent of this project is to minimize the number of breakers to be replaced by consolidating lightly loaded circuits and to put the substation back to normal configuration. Reliability: In June 2021, flooding in the Scotten (SCOTN) substation affected and condemned associated position breakers Other: The intent of this project is to minimize the number of breakers to be replaced by consolidating lightly loaded circuits and to put the substation back to normal configuration.
Yale-Slater Decommissioning and Circuit Conversion	Yale, St. Clair County, MI	Safety: 4.8kV causes a higher safety risk in the event of a wiredown. Reliability: SLATR DC2652 customers report voltage as low as 110V. Capacity: SLATR substation is at 112% of Firm. SLATR DC2652 is at 112% of DD and exceeds the DDO limit of 3MVA. YALE's throw over circuit is unable to carry the load of YALE DC2615. YALE DC2633 is approaching the emergency rating of the throw over circuit soon will be unable to throw over. Operability: YALE and SLATR substations are surrounded by 13.2kV substations and therefore has limited jumpering capabilities. Other: SLATR substation lacks oil containment, potentially causing future environmental impacts. SLATR transformer is constructed on railroad ties that may add stress to the equipment.

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Table 1 Conversion Projects, Continued

Project Name	Municipality	Drivers
Unionville Decommissioning and Circuit Conversion	Unionville, Tuscola County, MI	Safety: Existing 4.8kV causes a higher safety risk in the event of a wiredown. Reliability: Ageing substation equipment increases risk of failure. Capacity: Unionville substation is a 4.8kV distribution substation with two load carrying circuits. The substation is 111% of its firm rating and 91% of its emergency rating. Unionville substation is equipped with three single phase 500kV transformers which are the limiting element at the substation. Fairgrove substation is adjacent to Unionville substation. It is 116% of its firm rating and 86% of its emergency rating. Fairgrove substation is equipped with a 2.5MVA transformer which is the limiting element at the substation. Operability: Limited jumpering capabilities. Other: There have been 7 Method of Service requests in the Unionville area but the requests did not move forward due to the substantial upgrade costs which has led to repeated escalation and MPSC complaints.
Unionville DC 301 B1 Conversion - resolve voltage problem	Unionville	Safety: Existing 4.8kV causes a higher safety risk in the event of a wiredown. Reliability: Two residential customers filed MPSC complaints in January 2023. These customers are seeing a larger voltage flicker driven primarily by a residential on-demand water heater operating. However, the area has a history of motor start issues. The area is predominately agricultural. All sites have motors that operate within limits but collectively operate outside of limits. The issues will persist and complaints will continue until work is done to improve the circuit performance. Capacity: Unionville substation is a 4.8kV distribution substation with two load carrying circuits. The substation is 111% of its firm rating and 91% of its emergency rating. Operability: Limited jumpering capabilities.
Zenon Circuit Conversion Phase 2	Detroit	Zenon Class A substation was constructed in 2012 with dual winding secondary voltage (4.8/13.2kV) transformers as a means to quickly transfer 4.8kV load from McKinstry substation while facilitating future 13.2kV conversion. Zenon Phase 1 was driven by the construction of the Gordie Howe International Bridge (GHIB) crossing, and the McKinstry substation conflicts with the project. Four 13.2kV circuits were commissioned to either remove, consolidate, and/or convert portions of McKinstry & West End in direct conflict with the bridge plaza and the remaining McKinstry circuits were transferred to the 4.8kV side of Zenon. Due to recent flooding events in the Scotten substation area, low reliability, high propensity of wiredowns on the 4.8kV system in the area, and load increases driven by West Riverfront and Corktown development, the second phase of Zenon Conversions is to be initiated. The scope within this project was submitted for Round 1 of GRIP/IIJA grants in 2023. The Company was not awarded a grant in Round 1 and is submitting a modified application in Round 2 in 2024. If the Company is awarded a grant in Round 2, the timing of the project will be accelerated. Safety: Zenon Class A substation was constructed in 2012 with dual winding secondary voltage (4.8/13.2kV) transformers as a means to quickly transfer 4.8kV load from McKinstry substation while facilitating future 13.2kV conversion Reliability: Recent flooding events in the Scotten substation area, low reliability, high propensity of wiredowns on the 4.8kV system in the area Capacity: Load increases driven by West Riverfront and Corktown developments Operability: Completing this work will decommission WSEND and SCOTN substation along with their associated 24kV trunk lines
Calla Circuit Conversion	Dexter	Safety: 4.8kV Wire down elimination Reliability: Customers on a DIMND circuit regularly experience frequent and long duration outages. For this circuit, the SAIFI 5 year average is 2.25 and SAIDI 5 year average is 681. Capacity: This circuit is also over the Distribution Design Order limit of 8 MVA. DIMND Substation is 137% of firm rating. Operability: Customers at the end of this circuit are about ten miles from the substation and regularly experience low voltage/power quality issues. It also has limited jumpering points and capacity in the area needed to relieve load at adjacent substations. Other: Calla Substation and one distribution circuit from Calla were commissioned in 2021. The second Calla circuit will be established to relieve load from Diamond Substation and address the circuit's issues (listed above).

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Table 1 Conversion Projects, Continued

Project Name	Municipality	Drivers
Lapeer - Elba Expansion and Circuit Conversion (Apollo)	Lapeer and Elba	Safety: 4.8kV causes a higher safety risk in the event of a wiredown. Reliability: Lapeer and Elba substations have aging infrastructure and islanded 4.8 kV systems. Elba has problematic subtransmission infrastructure that has a history of poor reliability performance and limits shutdown capability for operation and maintenance. Capacity: Lapeer substation has a 13.2kV substation and a 4.8kV substation. The 13.2kV substation is at 107% of its firm rating. One circuit is at its day-to-day rating with another one approaching its day-to-day rating. Four circuits exceed the Distribution Design Order limit of 8MVA for a 13.2kV circuit. Elba substation is a two circuit 4.8kV substation. It is 125% of its firm rating and the substation transformer exceeds its day-to-day rating. One circuit exceeds its day-to-day rating. General load growth has been strong in the area (6-8% in 2017 and 2018). Operability: Limited jumpering options are available at Elba substation since it is an islanded 4.8kV substation. Other: The Lapeer-Elba area has also experienced several low voltage and power quality issues.
Birmingham Decommission and Circuit Conversion	City of Birmingham, Troy, and Bloomfield Hills	Safety: Birmingham substation is at high substation outage risk Reliability: This project is to address the loading, aging infrastructure and substation outage risk at Birmingham substation. In addition, Quarton Rd. substation is a 1948 vintage switchgear. QTNRD circuits will be left as an island with no jumper capability after BIHAM conversion. QTNRD has significant number of customer complaints due to aging infrastructure. Capacity: The substation is operating at its substation firm rating. Any new customer load or hot summer days will place the substation over its firm rating and in violation of DTE Electric's Distribution Design Standards. Operability: Birmingham substation, mainly serving downtown Birmingham, has a high substation outage risk. The stranded load is estimated at 21 MVA after possible load transfers and 19 MVA after mobile fleet deployments.
Hemlock Decommissioning and Circuit Conversion - 01	Ann Arbor	Safety: Mitigating 4.8kV wire downs and replacing aging infrastructure including equipment at an approximately 67 year old substation will improve public and operational safety Reliability: SAIFI 5 year average is 1.00 and SAIDI 5 year average is 485. Capacity: Two circuits exceed the Distribution Design Order limit of 3MVA for a 4.8kV circuit. Hemlock (HEMLK) is a 4.8kV substation that is at 93% of its firm rating. The Ann Arbor area has a high percentage of electric vehicle adoption and has a goal of carbon neutrality and the elimination of natural gas heating; as a result, there is a 44% projected 15-year load growth in the area. Operability: Hemlock area is adjacent to both 13.2kV and 4.8kV substation areas which limits the jumpering capabilities for emergency restoration.
White Lake Decommissioning and Circuit Conversion	White Lake Twp., Springfield Twp., Highland Twp., Rose Twp.	Safety: 4.8kV causes a higher safety risk in the event of a wiredown. Reliability: WHTLK substation is an older substation with multiple at-risk equipment that need to be upgraded or replaced. There is also a 40kV capacitor (CAP1-1) that has multiple at-risk equipment in need of upgrade or replacement. The existing substation site is too small to support replacing major equipment. Capacity: White Lake (WHTLK) has a 4.8kV substation and a 13.2kV substation. Each one has a single transformer and a single circuit. The 13.2kV substation is 88% of its firm rating. The circuit exceeds the Distribution Design Order limit of 8MVA for a 13.2kV circuit. The 4.8kV substation is 100% of its firm rating. The circuit is at 100% of its day to day rating and exceeds the Distribution Design Order limit of 3MVA for a 4.8kV circuit. Operability: White Lake circuits cannot be jumpered to one another because of the different operating voltages (4.8kV)

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1 **Q25. Are there specific 4.8 kV Conversion projects you would like to discuss in more**
2 **detail?**

3 A25. Yes. In addition to the CODI 4.8 kV conversion projects that are discussed later in
4 my testimony, I would like to highlight a couple of examples beyond what is
5 contained in the exhibits to establish a deeper understanding of their scope, the
6 rationale for making the investments, and the benefits customers will receive.

- 7 • I-94 Substation and Circuit Conversion (Promenade)
- 8 • Lapeer – Elba Expansion and Circuit Conversion (Apollo)

9
10 **Q26. What are the drivers of the I-94 Substation and Circuit Conversion**
11 **(Promenade)?**

12 A26. The Detroit I-94 industrial park is expected to add new commercial and industrial
13 customers to this area. This will result in increased loads that the current 4.8 kV
14 system will not be able to adequately support.

15
16 The Promenade project will also provide relief to the increased capacity demand
17 from the Detroit Public Lighting Department (PLD) conversions. This increased
18 demand is caused by the transfer of customers from the former Detroit owned PLD
19 system to the Company's system, resulting in overloads in some areas which
20 created planning criteria violations with detrimental impact to operational
21 flexibility and service reliability.

22
23 Also, the Promenade project address existing ITC transmission system loading
24 violations. Currently, the ITC transmission system feeding the east downtown area
25 has several Midcontinent Independent System Operator (MISO) loading violations

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1 which require mitigation. Engineers from ITC and DTE Energy collaborated to
2 develop a set of projects to resolve the transmission system violations, with
3 Promenade being one of these projects, resulting in a \$130M reduction over the
4 original proposed ITC solution.

5

6 **Q27. What is the scope of the I-94 Substation and Circuit Conversion (Promenade)?**

7 A27. This project is located on the eastside of Detroit and involves construction of the
8 new 120 kV to 13.2 kV Promenade substation and the conversion and transfer of
9 4.8 kV circuits out of Lambert, Lynch, and Pulford to the new Promenade
10 substation. In total 23 circuits (8 Lambert, 5 Lynch, and 10 Pulford circuits)
11 comprising of approximately 100 miles of 4.8 kV circuits will be modernized and
12 converted to six 13.2 kV circuits. Transferring the 23 circuits to Promenade will
13 support the decommissioning of Lambert, Lynch, and Pulford substations.
14 Additionally, the new 120 kV transmission feed will allow for the decommissioning
15 of four 24 kV trunk lines with a weighted average age (WAA)¹ of 90 years.

16

17 **Q28. What are the benefits of the I-94 Substation and Circuit Conversion**
18 **(Promenade) project?**

19 A28. The I-94 Substation and Circuit Conversion (Promenade) project eliminates
20 existing ITC transmission system violations and provides 30% additional
21 substation distribution capacity to serve residential, commercial, and industrial
22 customers in the city of Detroit and in the area southwest of Detroit City Airport.
23 The new 13.2 kV Promenade substation will support the decommissioning of
24 existing 4.8 kV substations Lambert, Lynch, and Pulford; all of which have

¹ Weighted Average Age - The ages of the cables weighted by length.

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1 surpassed the practical service life and are beyond 70 years old . Decommissioning
2 these substations will remove at risk equipment, including 10 transformers, more
3 than 20 regulators, more than 20 oil circuit breakers and disconnects, more than 20
4 miles of 4.8 kV underground cable, and more than 30 miles of 24 kV underground
5 cable. In addition to capacity, conversion of the circuits will improve safety and
6 reliability for the customers in this area with a projected 75-80% reduction in SAIDI
7 and removal of all PLD primary and arc wire in this area.

8

9 **Q29. What are the drivers of the Lapeer – Elba Expansion and Circuit Conversion**
10 **project?**

11 A29. Lapeer substation consists of 40 kV to 4.8 kV infrastructure and 40 kV to 13.2 kV
12 infrastructure, while Elba is a 4.8 kV substation. The Lapeer 4.8 kV substation is
13 approaching its firm rating at summer peak, and Elba substation has already
14 exceeded its firm rating (124%), thus it is unable to accommodate any additional
15 load growth in the area. Furthermore, there is no capability for Elba's downstream
16 load to be transferred to an adjacent substation since it is an islanded 4.8kV area
17 surrounded by 13.2 kV substations. This condition, if not mitigated, will result in
18 extended restoration time in the event of an outage due to equipment failure.

19

20 Elba substation is almost 70 years old and is fed from a 6-mile 40 kV dedicated
21 overhead line that has experienced poor reliability performance due to its location
22 in a heavily treed right-of-way with limited shutdown capability for operation and
23 maintenance. Due to the age of the electrical infrastructure in this area, there are
24 several reliability and operability concerns.

25

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1 **Q30. What is the scope of the Lapeer – Elba Expansion and Circuit Conversion**
2 **project?**

3 A30. This project is in Lapeer County, just north of I-69, and involves construction of
4 the new 120 kV to 13.2 kV Apollo substation. Once the Apollo substation is
5 energized, load from Lapeer, Hunters Creek, and Elba substations will be
6 transferred to Apollo and four 4.8 kV circuits totaling 32 miles from Lapeer and
7 Elba substations will be converted and consolidated to two 13.2 kV circuits.
8 Following the transfer of all load, the Elba substation, the 40 kV subtransmission
9 overhead line feeding Elba, and the 4.8 kV substation at Lapeer will be
10 decommissioned.

11

12 **Q31. What are the benefits of the Lapeer – Elba Expansion and Circuit Conversion**
13 **project?**

14 A31. The Lapeer – Elba project provides load relief and a 50 MVA capacity increase for
15 new growth in Lapeer County. The decommissioning of Elba and Lapeer 4.8 kV
16 substations will reduce outage risk by removing aging infrastructure from the
17 system. Additionally, new jumpering capability will be established with the
18 elimination of the 4.8 kV islanded system. Furthermore, reliability and power
19 quality will be enhanced with the upgraded distribution circuits and elimination of
20 the poor performing 40 kV overhead infrastructure feeding Elba.

21

22 City of Detroit Infrastructure (CODI) Conversion Program

23

24 **Q32. What geographic areas of Detroit are addressed by the CODI program?**

25 A32. As shown in Figure 3, the CODI program directly impacts the core Downtown,
26 Midtown, and New Center areas of Detroit. Additional projects within the CODI

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1 program will improve system reliability and safety in extended areas including
2 Eastern Market, Corktown, Woodbridge, Island View, and the West and East River
3 Fronts.

4 **Figure 3 CODI Scope Area**



5

6 **Q33. How many customers are served in the CODI area?**

7 A33. There are 31,800 customers served in this area including 27,486 residential, 4,299
8 commercial, and 15 industrial customers. Because customers are counted on a per
9 meter basis, in some cases a single customer count in the CODI area could be a
10 large commercial building, such as the Renaissance Center or a multi-tenant
11 building with hundreds of residential tenants. In addition to residential housing, this
12 area of Detroit is vital to hospitals, universities, tourism, and recreation in the region
13 including shopping, major sports and cultural venues, and parks.

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1 **Q34. What are the drivers of the CODI program?**

2 A34. The earliest electrical grid in southeast Michigan was developed in the downtown
3 area in the city of Detroit. Significant portions of the electrical infrastructure in
4 Detroit were placed in service in the early part of the 20th century, and much of
5 that original infrastructure remains. For example, Garfield substation was
6 constructed in 1930 and still provides electrical service to the Midtown area of
7 Detroit surrounding Wayne State University and the museum district. The early
8 electrical system architecture was designed to be extremely reliable; but as the age
9 of the infrastructure has increased, so have the equipment failure rates. These
10 customers continue to experience power outages and power quality issues from
11 equipment failures related to aging infrastructure on the system (4.8 kV & 24 kV
12 cable, netbank transformer, and substation induction regulator failures).

13
14 In addition to the challenge of aging equipment, the downtown CODI area has
15 experienced 9.5% load growth (31 MVA) in the last decade, with the potential for
16 an additional 10% load growth by the end of 2035. Additional load growth is
17 mainly driven by the completion of downtown development projects in
18 construction whose completion was delayed by the pandemic, known developer
19 and economic development projects, and increased electrification.

20
21 The CODI area is extremely critical to the City of Detroit and the Michigan
22 economy. Therefore, the system aging infrastructure, which is nearing one hundred
23 years in service, must be upgraded to maintain its integrity and to serve the
24 increasing load in the area. Some of the notable new load projects in the last decade
25 are Little Caesars Arena, David Whitney Building, Q Line Light Rail System,

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1 Wayne State School of Business and Hillberry Theater Expansion, Book Tower,
2 David Stott Building, Detroit Pistons Performance Center, and the Huntington
3 Bank Tower. These along with dozens of other completed new build/renovations
4 in the New Center, Midtown, and Central Business District areas of Detroit have
5 created significant load growth and economic momentum in the CODI area, which
6 will continue with the pipeline of future projects.

7

8 **Q35. Are there additional drivers for the CODI program?**

9 A35. Yes. The load growth realized over the last decade and projected in the future are
10 not the only drivers of the CODI program. The aged 4.8 kV & 24 kV electrical
11 infrastructure (substations, underground cable, manholes, network equipment, and
12 other assets) in this area is experiencing higher failure rates which increases the risk
13 of long-duration outages impacting customers and leading to high reactive
14 maintenance costs. Eighty percent of the installed 4.8 kV and 24 kV infrastructure
15 in the CODI footprint has been in service for over 60 years and is considered “at
16 risk” as evidenced by the historical failure rate curve shown in Figure 4.

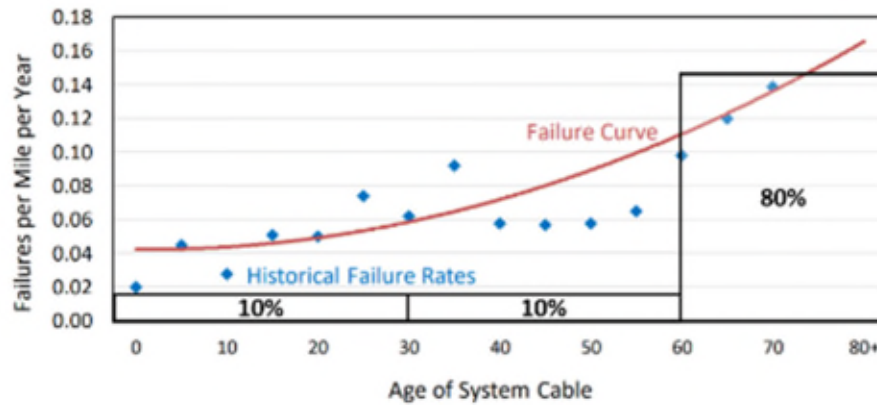
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Figure 4 CODI 4.8 & 24 kV mileage distribution over system failure

2

rate curve

3

4 The existing 4.8 kV multi-level in-building substations are space constrained to
 5 install or replace infrastructure with modern equivalents. Vintage equipment
 6 continues to be refurbished or repaired post failure and put back into service. This
 7 practice is not only costly, but it is also not considered to be good utility practice.
 8 The continued implementation of the CODI program is necessary to address this
 9 aging infrastructure to serve the customers safely and reliably.

10

11 **Q36. What are the challenges with implementing the CODI program?**

12 A36. Due to the complexity and the interdependency of the electrical infrastructure in
 13 this area, the Company developed the CODI program. The construction of new
 14 substations, upgrades to existing substations, converting the existing AC network
 15 system from 4.8 kV to 13.2 kV, and additional circuit upgrades must be sequenced
 16 and conducted in a robust, multi-year program as opposed to individual projects in
 17 isolation to each other. These projects require complex system shutdowns in a
 18 congested downtown district that must be managed carefully due to the critical

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1 customer loads that will be impacted, including hospitals, federal and municipal
2 emergency centers, and multiple corporate headquarters. The CODI program is
3 sequenced to perform the needed upgrades in a manner that is least impactful to
4 customers.

5

6 **Q37. What unique drivers that support prioritizing the CODI program to be**
7 **completed in the next decade?**

8 A37. The CODI area is served primarily by an all-underground system with manhole
9 access located in busy city center streets. Its reliability is dependent upon the ability
10 to have redundant capacity available on all power lines to transfer load in the event
11 of cable failures or planned shutdowns on the distribution and subtransmission
12 systems. This system is designed for N-1 contingency situations, which means that
13 if a single trouble event is occurring on the system at any one time, the system is
14 still able to serve all load. Manholes typically support multiple system cables, and
15 a failure of one cable can impact adjacent cables resulting in cascading failures.
16 Due to the amount of aging high-risk cable and equipment, the integrity, and the
17 reliability of the underground system is compromised. This has resulted in an
18 increased frequency of cases of multiple trouble events occurring simultaneously
19 that are beyond the original system design criteria (N-1-1 and N-2 events) resulting
20 in critical customer outages or complex contingency staging and planning of
21 emergency equipment throughout downtown Detroit. Frequently when outage or
22 next contingency events do occur in the CODI area, the Company has limited
23 ability to respond and restore customers with alternative emergency measures; such
24 as portable substations, diesel generators, or circuit load transfers given the space
25 constraints of the congested downtown environment, inaccessible underground

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1 Company infrastructure, and customer service gear located deep below grade in sub
2 basements. These contingency plans are often not only time consuming but
3 extremely challenging to execute.

4

5 When the CODI strategy was first conceptualized in 2015, the majority of the 24
6 kV and 4.8 kV cable in scope had a weighted average age of 65 years with some of
7 the oldest sections being beyond 90 years of service age. With the current target
8 completion date of 2035, sections of 4.8 kV and 24 kV cable will be in service for
9 over 110 years at that point. With the failure rate of paper and lead cable increasing
10 with age, these cables must be replaced to maintain the integrity and reliability of
11 the system. The current pace of the CODI program addresses these necessary
12 replacements in the maximum allowable timeframe and the Company continues to
13 seek ways to increase efficiencies and accelerate implementation.

14

15 To ensure crew safety, DTE underground work rules prohibit personnel from
16 entering manholes with swollen or leaking lead sleeves, shown in Figure 5, due to
17 the possibility of an imminent failure, and therefore, these cables may need to be
18 de-energized before entering.

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Figure 5 Leaking & swollen sleeve examples



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An increasing frequency of these types of adjacent hazards occurring simultaneously within the same manholes requires the Company to go to significant and impactful measures and implement emergency responses such as customer intentional interruptions, installation of temporary cable at grade, distributed generator staging installation in tight urban areas requiring street shutdowns, and expensive temporary re-routes of circuits, etc. to address safety issues and restore the system to normal.

The only method to completely mitigate the undergrounding reliability and safety issues is the replacement of old paper and lead cable with new ethylene propylene rubber (EPR) cable that does not have the same high failure rates and hazard issues with lead joints. The CODI program complements other grid investment programs by also reducing the totality of the 4.8 kV and 24 kV system that need to be replaced.

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1 Without these investments, the increasing failure rates of aged equipment, coupled
2 with the load growth in the CODI area, will increase the frequency of outage events
3 that affect large portions of the downtown system. These events will impact more
4 customers and become more expensive and complicated to repair and restore.

5

6 **Q38. What is driving the near-term AC Network replacements that are a critical**
7 **part of the CODI program?**

8 A38. The AC Network distribution system is recognized industry wide as the most
9 reliable circuit topology due to its meshed design with multiple, parallel sources.
10 This reliability advantage can only be preserved when the system is operated within
11 its contingency design, which for the DTE Energy AC Network is N-1.

12

13 Due to the age of the system with components beyond their useful life, it is common
14 for the Detroit AC Network to experience concurrent failures. These failures can
15 lead to customer and system impacts including cascading low voltage issues, grid
16 fires, manhole eruptions and customer outages. Table 2 lists the AC network outage
17 events from 2016 through 2023.

18

Table 2 AC Network Outage Events (2016-2023)

YEAR	FAILURE EVENTS	N-1	N-1-1	N-2	OUTAGE EVENTS
2016	24	21	1	2	3
2017	21	20	1	0	1
2018	19	17	2	0	2
2019	27	22	3	2	5
2020	14	12	1	1	2
2021	15	11	3	1	4
2022	16	12	2	2	4
2023	16	15	1	0	1
TOTAL	152	130	14	8	22

19

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1 The downtown Detroit AC Network has experienced customer outages 22 times
2 since 2016 or an average of 2.75 outages per year. This is concerning, as AC
3 Network systems normally provide reliability that exceeds radial systems.
4 Typically, a network customer can expect to be out of service once every 58 years
5 and experience 4% of the interruptions of a radial underground system (New York
6 Public Service Commission, 2009 as quoted in Smith & Moffat 2010) ².

7

8 Downtown Detroit AC Network customers have not only experienced significantly
9 more outages than typical indices, which will become more frequent as age related
10 failure rates increase (as shown in Figure 4 above), but AC Network outages are
11 also long duration events that are difficult to quickly restore as previously stated.
12 Typical CAIDI for networks is 3.4 times longer than that of a radial system (New
13 York Public Service Commission 2009 as quoted in Smith & Moffat 2010).

14

15 The existing AC Network system, operating at 4.8 kV, is capacity constrained in
16 some local areas of growth based on cable size and number of network feeders, thus
17 necessitating the conversion to a higher voltage class. Conversion allows for fewer
18 network feeders to serve a given area of the system while increasing capacity. The
19 Garfield Network Conversion project, as an example, reduces the number of
20 netbank transformers required by 30% but increases Network Capacity by 21.8
21 MVA, all while reducing the weighted average age of the system primary cable by
22 69 years at project completion. The reduction in equipment will reduce associated
23 maintenance costs over time. Figure 6 shows some of the Garfield AC network
24 project benefits.

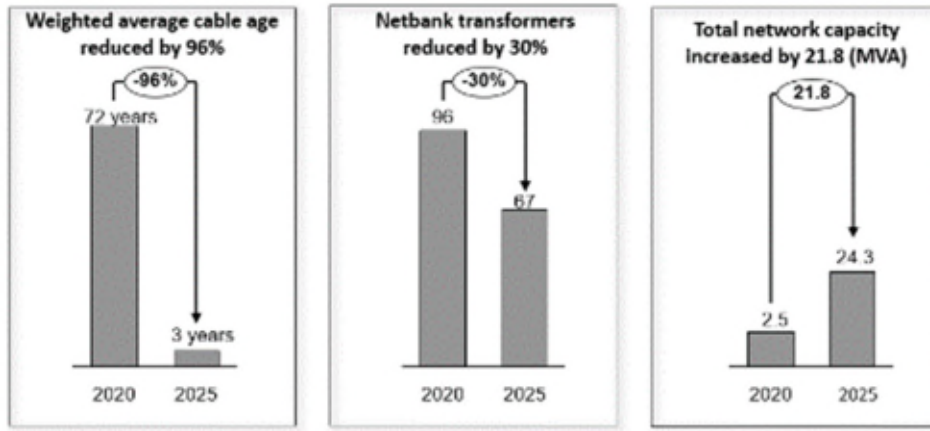
² D. Smith and J. Moffat, "EPRI Underground Distribution Systems Reference Book" (City: Publisher, 2010), Chapter ~~24~~¹², p. 21.

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Figure 6 Garfield AC Network Project Benefits

2



3

4 **Q39. What is the scope of the projects in the CODI program included in this case?**

5 A39. The CODI program converts and consolidates substations, the AC network, and
6 associated overhead circuits. This program will construct two new 13.2 kV
7 substations (Corktown and Island View), expand three existing 13.2 kV substations
8 (Midtown, Alfred, and Cato), and decommission five 4.8 kV substations (Charlotte,
9 Walker, Howard, Kent, and Gibson). This program also converts and consolidates
10 the AC network system, as well as converting and consolidating the associated
11 overhead circuits from 4.8 kV to 13.2 kV. The program also includes
12 decommissioning the aged underground 4.8 kV and 24 kV cables in the CODI
13 footprint as shown in Figure 3. Table 3 provides a high-level summary of the
14 projects in the CODI program with additional details provided in Exhibit A-23
15 Schedule M6.

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Table 3 City of Detroit Infrastructure Projects

2

Project	Key Scope of Work	Estimated Timeline
CODI: Charlotte Network Upgrade	* Rebuild 30 miles of network feeder cable * Rebuild 7 miles of system cable * Replace or remove 83 netbank transformers * Convert 8 primary customers * Convert the circuits to 13.2kV * Decommission Charlotte substation	2016-2025
CODI: Targeted Network Secondary Cable Replacement	Replace targeted sections of the secondary network cable system that have a higher probability of failure	2017-2025
CODI: Midtown Substation Expansion	Expand 13.2kV Midtown substation by installing a 3rd transformer and a 12-position switchgear	2017-2024
CODI: Alfred Substation Expansion	Expand 13.2kV Alfred substation by installing a 3rd transformer and a 12-position switchgear	2018-2025
CODI: Corktown Substation	Build a new general-purpose substation	2018-2023
CODI: Garfield Network Upgrade	* Rebuild 36 miles of network feeder cable * Replace or remove 78 netbank transformers * Convert 24 miles of overhead * Convert and consolidate the circuits to 13.2kV fed by Stone Pool substation * Remove 4.8kV and 24kV cable and decommission Garfield substation	2019-2026

3

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Table 3 City of Detroit Infrastructure Projects, Continued

Project	Key Scope Of Work	Estimated Timeline
CODI: Islandview Substation	*Construct a new 13.2kV substation * Convert 32 existing 4.8kV circuits from Walker and Pulford *Decommission Walker substation * Decommission aging 24kV cables and infrastructure	2020-2031
CODI: Kent/Gibson Conversion	<u>Kent Substation</u> * Rebuild 6 miles of system cable * Convert 1 primary customer * Convert 7 miles of overhead * Convert and consolidate the circuits to 13.2kV fed by Corktown substation * Decommission and remove 2 miles of 4.8kV cable * Remove 24kV cable and equipment * Remove 6 breakers and decommission Kent substation <u>Gibson Substation</u> * Rebuild 10 miles of system cable * Convert 22 miles of overhead * Convert and consolidate the circuits to 13.2kV fed by Corktown substation * Decommission and remove 4 miles of 4.8kV cable * Remove 24kV cable and equipment * Remove 8 breakers and decommission Kent substation	2021-2028
CODI: CATO Substation Expansion	Expand 13.2kV Cato substation by installing a 3rd transformer and a 12-position switchgear	2021-2027

2

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Table 3 City of Detroit Infrastructure Projects, Continued

Project	Key Scope Of Work	Estimated Timeline
CODI: Garfield Radial (Midtown Circuits)	* Convert 17 miles of overhead from 4.8kV to 13.2kV * Convert 11 primary customers from 4.8 kV to 13.2 kV * Convert and consolidate the circuits to 13.2 kV fed by Midtown substation * Decommission 5 miles of UG cable	2022-2026
CODI: Howard Conversion	* Rebuild 6 miles of network feeder cable * Rebuild 12 miles of system cable * Replace or remove 89 netbank transformers * Convert 26 primary customers * Convert 3 miles of overhead * Convert and consolidate the circuits to 13.2kV fed by Corktown, St. Antoine, Cato, and Temple substations * Decommission Howard substation	2023-2032

2

3 **Q40. What steps is the Company taking to ensure that the CODI program is**
4 **executed successfully to achieve the projected investment forecast?**

5 A40. The Company's recently formed Project Management Office (PMO) is using
6 developed project management expertise as well as updated processes and
7 leveraging project learnings to ensure the successful execution of all DO capital
8 projects, including the CODI program. The formation of this team focused on
9 construction of investments is further discussed by Witness Kryscynski.

10

11 The Charlotte and Garfield AC Network conversion projects were able to identify
12 the equipment, technologies, and standards that would be used in AC network and
13 urban underground conversions going forward. As a result, in these early projects,
14 much of the up-front investment was in foundational engineering and design
15 considerations that will benefit subsequent projects. With this work now

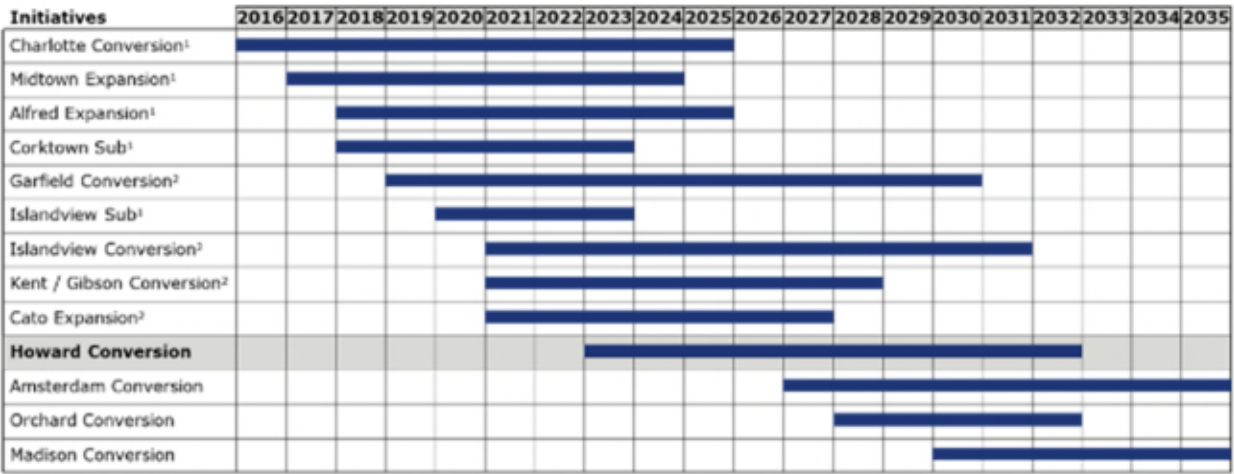
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1 completed, the pace of field execution will be able to advance faster on inflight and
2 future projects.
3
4 The initial years of the CODI project, as shown in Figure 7, were used to construct
5 much of the 13.2 kV substation infrastructure, to support the subsequent projects
6 including circuit conversion and the transfer load from the 4.8 kV CODI systems.
7 During this timeframe, the construction was limited to only a few simultaneous
8 projects (Midtown, Alfred, Island View and Corktown substation) and the CODI
9 funding levels reflected these limited investments. Currently, in the ninth year of
10 this program as shown in Figure 7, up to eight simultaneous projects of multiple
11 labor resource types (substation, conduit/netbank construction, underground
12 pulling and splicing, and overhead pre-conversion and conversion) are running at
13 any one time in different areas of the CODI system. The CODI program can now
14 support an increased level of spending because the different design and labor
15 resources do not conflict with one another's execution.

16

17 **Figure 7 CODI Strategy Initiatives and Projects**

18



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1 4.8 kV ISO Conversion Program

2

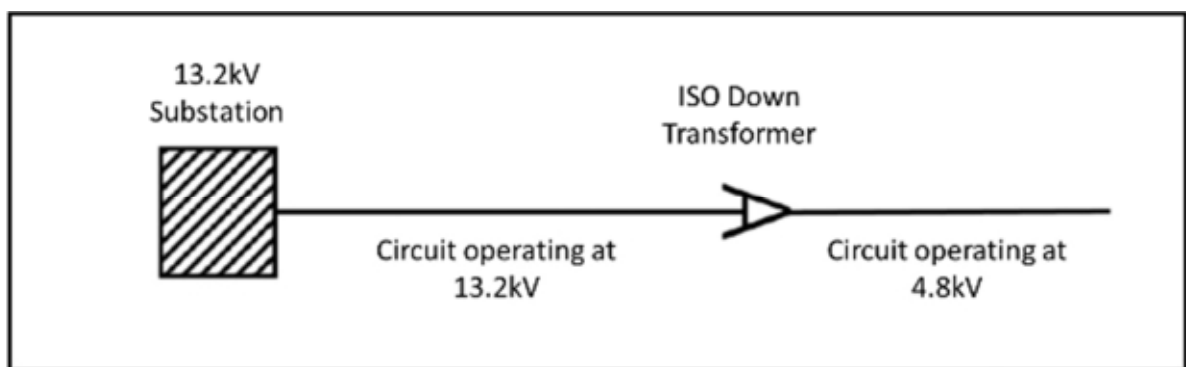
3 **Q41. What is an ISO down?**

4 A41. In some areas, the Company operates portions of circuits at 4.8 kV fed from a 13.2
5 kV substation, known as isolation down circuits (ISO down). The reason for this
6 grid configuration is that in some instances, there was a need to address immediate
7 overloading on a circuit or circuits fed from a substation at which other circuits
8 were not overloaded. The circuit overload issue can be addressed by building a
9 higher voltage substation, typically 13.2 kV, and initially converting only the
10 overloaded circuits, or portions of the circuits, to the higher voltage, while operating
11 the remaining non-overloaded circuits at the existing voltage, typically 4.8 kV.
12 Portions of the circuits which were not modernized and converted to 13.2 kV will
13 include an isolation down transformer and continue to be served at 4.8 kV. Figure
14 8 illustrates a 13.2 kV circuit utilizing an ISO down.

15

16

Figure 8 “ISO” Down Example



17

18 Table 4 provides the number of circuits with ISO downs, number of customers
19 served, and the 4.8kV OH and underground line miles.

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2**Table 4 Number of Circuits with ISO Downs**

	Number of Circuits	Number Of Customers	Miles Overhead Circuit	Miles Underground Circuit
4.8kV ISO Downs	432	142,335	5,596	417

3 **Q42. Why are ISO downs not considered a permanent solution to address**
 4 **overloaded circuits?**

5 A42. The installation of ISO's has been a cost-effective and faster approach to address
 6 loading concerns at source substations without full conversion of the entire
 7 downstream circuits. This was always intended as a temporary measure. While at
 8 the time they didn't face the overloads that caused the substations and some circuits
 9 to be converted, the 4.8 kV ISO downed areas of the circuits have not been
 10 upgraded or modernized and have the same characteristics of ungrounded 4.8 kV
 11 circuits fed from 4.8 kV substations. They have the same reliability issues, safety
 12 risks, and operational concerns, and face the same challenges when it comes to
 13 incorporating increasing EVs and DERs.

14

15 **Q43. What is the scope of work for converting ISO down circuits?**

16 A43. Similar to circuit conversions that are part of the Conversions program, the ISO
 17 down program is aimed at modernizing the 4.8 kV portions of the circuits to a
 18 higher voltage. The scope of work for the 4.8 kV ISO down conversions includes:

- 19 • Completing overhead pre-conversion work including rebuilding pole tops,
 20 replacing poles and transformers as needed, and installing neutral wire.
- 21 • Rebuilding underground infrastructure as needed.

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- 1 • Reconductoring overhead wires as needed based on new circuit
- 2 configurations and existing wire size.
- 3 • Reconfiguring circuits and establishing new jumpering points.
- 4 • Installing controls and automation in the substations and circuits to our latest
- 5 design standards
- 6 • Removing ISO down transformers.
- 7

8 **Q44. What are the benefits of the 4.8 kV ISO Conversion program?**

9 A44. The ISO conversion projects are expected to bring multiple benefits similar to full
10 conversion projects, including safety improvements by reducing wire downs,
11 improving reliability through newly updated equipment, enabling technology
12 modernization, providing additional capacity; and avoiding costs associated with
13 increasing failure of aging infrastructure. Like a full conversion and consolidation
14 project, 4.8kV ISO conversions are expected to deliver up to 90% reliability
15 improvements for the areas impacted, as described in detail starting on page SSD-
16 14.

17

18 **Q45. How are circuits in the 4.8kV ISO Conversion program prioritized?**

19 A45. The 4.8kV ISO Conversion program is ranked as a whole using the GPM which
20 considers substation firm rating, circuit overloads, wire downs per OH mile,
21 substation risk, and energy justice (EJ), as discussed in detail by Witness
22 Kryscynski. The Company prioritizes the order to address ISO down locations
23 based on specific criteria, with safety being the primary driver in the prioritization
24 efforts. Work is prioritized at the substation level, as it is more efficient to plan and
25 perform the work for the group of circuits tied to the same substation. Each ISO

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1 down is scored based on the following factors, with total scores rolling up to the
2 substation level:

3 1) Recorded wire downs;

4 2) Total substation SAIDI;

5 3) Total outage and non-outage events, such as low voltage, requiring the dispatch
6 of a line crew.

7

8 Additionally, the Company recognizes that other priorities such as load growth and
9 the need for operational flexibility are also important considerations in determining
10 the execution order of ISO down conversion and will incorporate these
11 considerations on as needed basis.

12

13 Work to begin 4.8 kV ISO conversions has been initiated on the four highest
14 priority substations, which are shown in Table 5.

15

Table 5 ISO Conversion Rankings

Ranking	Substation	Community	4.8kV miles to convert
1	Camden	Pontiac	3.8
2	Kern	Pontiac	8.3
3	Gilbert	Romulus	5.8
4	Biddle	Wayne	11.7

16

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1 8.3 kV Pontiac Conversion

2

3 **Q46. What are the drivers of the 8.3 kV Pontiac Conversion program?**

4 A46. The Pontiac area is the only 8.3 kV in the Company's distribution system, as the
5 system was acquired from CMS Energy in the 1980s (additional detail on the 8.3
6 kV system can be found in Exhibit A-23 Schedule M8 DGP starting on page 123).
7 Unlike the 4.8 kV and 13.2 kV systems, contingency options to support alternate
8 routing of power under an outage situation are very limited for the 8.3 kV system
9 through jumpering. The 8.3 kV system is essentially an island surrounded by the
10 13.2 kV system, making it extremely challenging to transfer load from 13.2 kV
11 circuits to 8.3 kV circuits and from 8.3 kV circuits to 13.2 kV circuits. This results
12 in a high risk for stranded load in the event of a substation outage event.

13

14 Adding to this operational challenge, the 8.3 kV system is aged, and many
15 replacement parts are no longer available. Due to the design configuration and
16 timeframe when these substations were built, they have tighter, non-standard
17 clearances between equipment. For Company employees to prevent arc flashes and
18 maintain safe working conditions, total substation shutdowns are required when
19 doing equipment maintenance, versus isolating a single piece of equipment as is
20 done in other voltage substations. This leads to extended customer interruptions
21 during outage events and leaves the system in an abnormal state for extended
22 periods of time if any 8.3 kV equipment fails.

23

24 Additionally, the 8.3 kV conversion program is necessary to increase capacity,
25 improve reliability, safety, and operability.

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1 **Q47. What is the scope of the 8.3 kV Pontiac Conversion Program?**

2 A47. The 8.3 kV system is served by four substations: Bartlett, Paddock, Rapid Street,
3 and Stockwell and their combined eighteen (18) distribution circuits. The plan to
4 address the 8.3 kV system has been developed, starting with upgrading the system
5 underground vaults, additional project detailed information is provided in exhibit
6 A-23 Schedule M6 as well as Section 9.3.7 of Exhibit A-23 Schedule M8 DGP.
7 The additional scope for converting the 8.3 kV system includes expanding the
8 existing 13.2 kV Catalina and Wheeler substations to add capacity. Once the
9 Catalina and Wheeler substation expansions are completed, the overhead and
10 underground infrastructure from Bartlett, Paddock, Rapid Street, and Stockwell
11 substations will be converted and transferred to new 13.2kV circuits.

12

13 Additionally, the 8.3 kV conversion program will decommission all four 8.3 kV
14 substations in the Pontiac area. The removal of at-risk, outdated, and obsolete 8.3
15 kV equipment from the system will reduce emergent costs and improve response
16 time for customer restoration.

17

18 **Q48. What are the 8.3 kV Pontiac Conversion projects included in this case?**

19 A48. The table below provides the high-level summary of the 8.3 kV Pontiac Conversion
20 projects included in this case. Detailed information for each of these projects is
21 provided in exhibit A-23 schedule M6.

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1

Table 6 8.3 kV Pontiac Conversion Projects

Project Name	Municipality	Drivers
Infrastructure to support decommission of (8.3KV) sub - Pontiac OH	Pontiac	Safety: 8.3kV causes a higher safety risk in the event of a failure due to aging and obsolete equipment Reliability: Replacement parts are no longer available for 8.3 kV breakers, other substation equipment. Non-standard clearances require substation shutdowns for operations and maintenance. This leads to extended customer interruptions during outage events and leaves the system in an abnormal state for extended periods of time if any 8.3 kV equipment fails. Capacity: The City of Pontiac is experiencing an economic rebound, with an estimated 40 MVA (37 percent) load growth in the next five to ten years. Operability: Because the 8.3 kV system is an island surrounded by the 13.2 kV system, it is impossible to transfer load from 8.3 kV circuits to neighboring facilities. This results in a high risk for stranded load in the event of an 8.3kV substation outage event.
Pontiac Underground Conversion	Pontiac	Safety: The aging 8.3kV system in Pontiac is obsolete and pose safety hazard for any repairs needed to be made. Reliability: Replacement parts are no longer available for 8.3 kV breakers, other substation equipment and equipment in the underground vaults due to their obsolescence. Non-standard clearances require substation shutdowns for operations and maintenance. This leads to extended customer interruptions during outage events and leaves the system in an abnormal state for extended periods of time if any 8.3 kV equipment fails. Operability: The 8.3kV system serves 29.5MVA of load and over 7,000 customers. The largest services are delivered through 8.3kV rated underground equipment. These services contain customer-owned switchgear, fuses, and transformers. Replacement of the 8.3kV substations with 13.2kV infrastructure requires the replacement of these services with 15kV rated equipment to enable better operability.

2

3 **Q49. What are the benefits of the 8.3kV Pontiac Conversion?**

4 A49. Like the other conversion programs, the 8.3 kV Pontiac conversion program is

5 projected to provide a net percentage reduction of up to 90% in customer minutes

6 of interruption, wire downs, and trouble events. Additionally, converting the

7 Pontiac system to 13.2kV will provide jumpering points from nearby 13.2 kV

8 substations. This will improve system operability and reduce outage restoration

9 time by allowing the Company to restore customers prior to repairing future

10 damaged infrastructure (restore before repair). The expanded 13.2 kV Wheeler

11 substation will provide capacity for future needs and better prepare the area for

12 adoption of EVs and DERs.

13

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1 Subtransmission Redesign & Rebuild

2

3 **Q50. Can you describe the Company's Subtransmission system?**

4 A50. The Company's Subtransmission system is an interconnected web that transmits
5 higher transmission voltage across the service territory to stations that step down
6 the voltage to distribution levels to serve customers. The subtransmission system
7 (operated at the voltages of 24 kV, 40 kV, or 120 kV) provides a vital service as
8 each subtransmission circuit serves one or more distribution substations, which
9 directly feed customers.

10

11 The design of the subtransmission system is intended to provide redundancy and
12 therefore greater reliability to the feed points of the distribution substations. The
13 redundancy provides continued service to the customers during a single
14 contingency situation³.

15

16 The Company's subtransmission system differs from that of most other utilities
17 because it includes station equipment, radial, and network designs. The radial
18 configuration, called a trunk line shown in Figure 9, has one source station which
19 then feeds one or multiple substations. The network configuration, called a tie line
20 shown in Figure 10, has multiple source stations, and feeds multiple substations.

21

³ The contingency state exists when there is an unplanned loss/failure of a component of the electric power system (e.g., transformer, cable, wire or breaker).

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The Company utilizes a coordinated system of automatic pole top switches (APTS) and line section breakers on the networked tie lines to isolate faults and maintain service to customers during single contingency failure situations.

Figure 9 Subtransmission Trunk Line Configuration

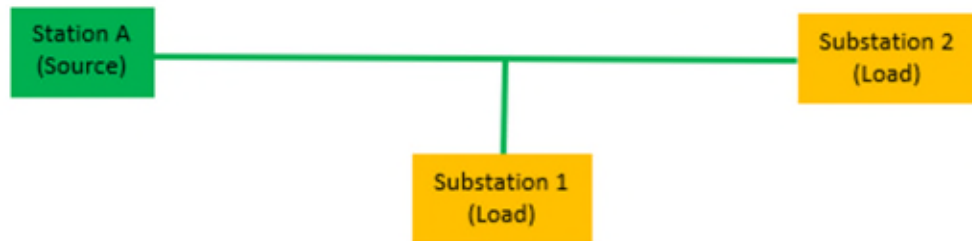
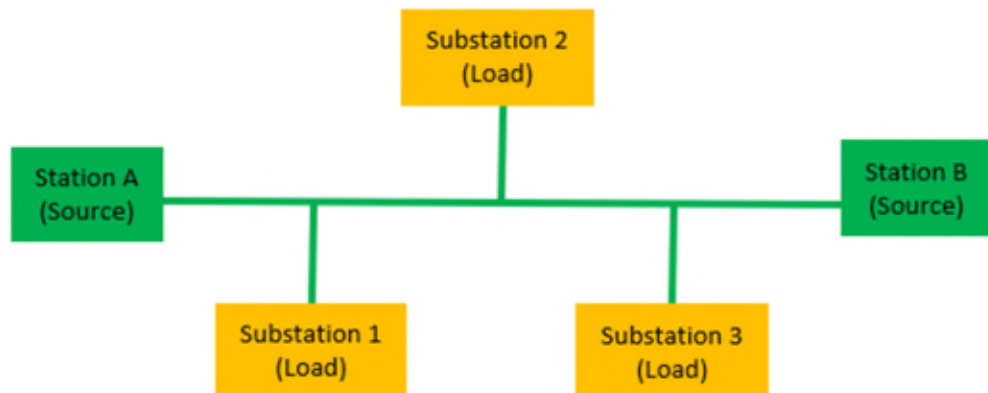


Figure 10 Subtransmission Tie Line Configuration



Q51. **What type of analysis was performed to determine potential capacity limitations in the subtransmission system?**

A51. Subtransmission Planning Engineers analyze the condition of the system annually to determine any existing or potential limitations to having adequate capacity to

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1 support customers in a single contingency situation. This analysis is conducted by
2 utilizing industry-standard modeling software (PSSE & TARA), using both
3 individual substation loads, and electric models used by the Midcontinent
4 Independent System Operator (MISO).

5
6 The electric models provided by MISO include multiple system loading scenarios,
7 including current and projected future peak loading conditions. Using these
8 models, the engineers run a study on each individual subtransmission trunk or tie
9 line, with potential contingency situations assessed to identify all violations of
10 subtransmission planning criteria. The planning criteria focuses on both thermal
11 overloads and voltage violations under normal system conditions and during a
12 single contingency configuration. A thermal overload indicates that load on the
13 equipment on the circuit or station exceeds its rating, and a voltage violation
14 indicates that the voltage on at least part of the circuit is no longer within an
15 acceptable range. Similar methodology and guidelines are commonly used by other
16 utilities when performing their capital planning.

17

18 **Q52. Why does the company plan to a single contingency scenario for the**
19 **subtransmission system?**

20 A52. The company, consistent with standard industry planning approach, plans to a
21 single contingency scenario to provide continued service to customers in an outage
22 event. As an example, Figures 11 and 12 show a high-level trunk line configuration
23 in normal and single contingency scenario respectively. In a normal configuration,
24 two different trunk lines feed the multiple substations. Substations 1, 2, and 3 load
25 will be split between the two subtransmission circuits, as shown in Figure 11.

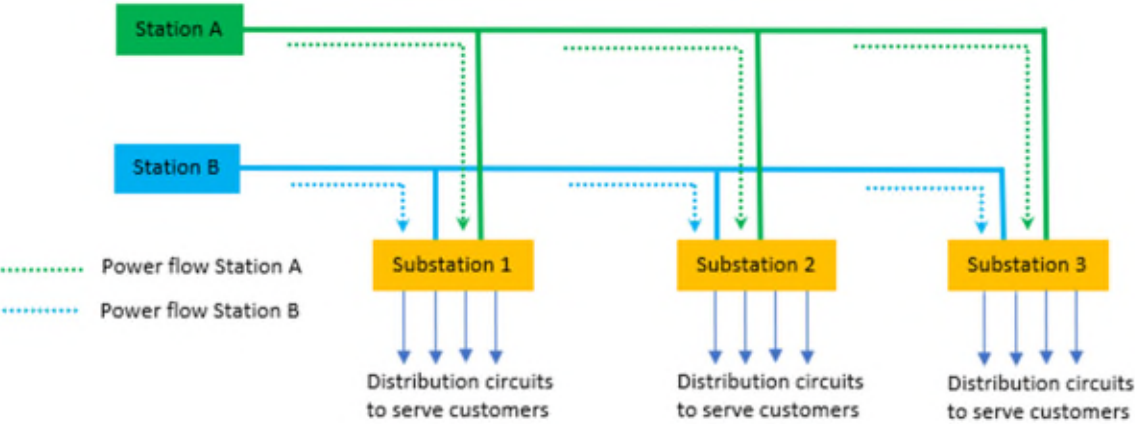
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1 When one of the subtransmission circuits experiences an outage (single
2 contingency), the second subtransmission circuit will have to carry all the load
3 served by substations 1, 2, and 3 to prevent an extended outage, as shown in Figure
4 12. If this redundancy is not available, then the result is potentially a long duration
5 outage that requires the deployment of costly mobile generation or portable
6 substations to restore customers.

7

8 **Figure 11 Subtransmission Normal Trunk Line Configuration**

9



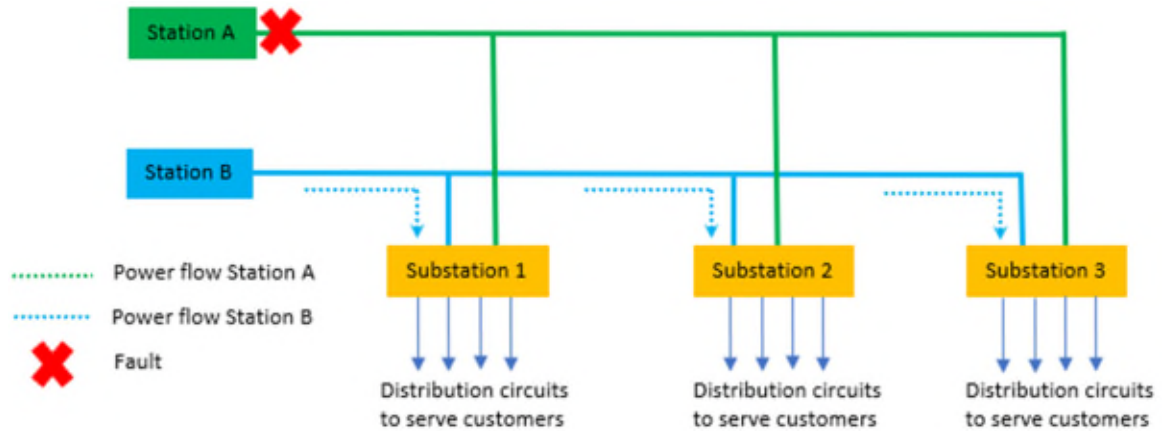
10

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Figure 12 Subtransmission Single Contingency Trunk Line

2

Configuration

3

4 **Q53. What are the challenges and issues associated with the subtransmission**
 5 **system?**

6 A53. Similar to the distribution system, the subtransmission system is experiencing
 7 aging, beyond 80 years old in some areas, and storm related resiliency challenges,
 8 as well as increased loading in some areas, leading to loss of contingencies. Some
 9 areas of the subtransmission overhead system are in difficult-to-access, deeply
 10 wooded areas and along railroads, increasing the time and difficulty for restoring
 11 service or maintaining equipment. These factors are leading to an increased number
 12 of failures on both the overhead and underground subtransmission systems and
 13 lengthy restorations. Because of the role of subtransmission in powering and
 14 connecting substations in the larger grid, these failures can often result in much
 15 larger sustained outages as well as the loss of redundancy, depending on the system
 16 configuration. An outage event on the distribution system, downstream in the grid
 17 from the subtransmission system, can typically impact up to ~1,000 customers,
 18 depending on the size of the circuit. By comparison, an outage on the

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1 subtransmission system, because it's upstream in the grid, can impact multiple
2 substations, which in some areas can result in more than 10,000 customers
3 impacted.

4

5 Capacity analysis of the subtransmission system is performed annually, where
6 actual and forecasted, loading is compared to a standard or target state, which is
7 called "planning criteria." The Company performed an analysis on the
8 subtransmission system that revealed approximately one-third of the circuits miles
9 on the subtransmission system violated the Company's planning criteria. These
10 violations have been/will be analyzed by the engineering team, and projects to
11 resolve the capacity constraints are/will be developed.

12

13 In addition to current performance challenges impacting customer reliability, the
14 analysis showed that the Company's aging subtransmission system overall is not
15 adequate to serve short and longer-term needs, given its limited capacity and
16 reliability performance. In some areas of the grid loads have increased over time
17 and impacted customer outages by reducing the redundancy that is essential for
18 continued reliability as well as operability of the system. Existing overloads and
19 the aging equipment place loading constraints on the system. These constraints
20 limit the Company's ability to plan for shutdowns required for system upgrade
21 projects and routine maintenance to only be completed during periods of lower
22 loading or through the deployment of portable equipment. These periods of lower
23 loading are typically only during a few weeks in the spring and the fall season. The
24 loading constraints also make it challenging to add new customers or provide
25 additional capacity for existing customers with increased load.

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1 **Q54. What are the benefits of the Subtransmission Redesign and Rebuild Projects?**

2 A54. A rebuilt, hardened, resilient subtransmission system will dramatically improve
3 safety, reliability, and operability, and increase capacity. The resiliency of the
4 overhead subtransmission system will be achieved by rebuilding to the Company's
5 grade B standard which will harden against weather impacts such as high winds
6 and lightning. The rebuilt overhead subtransmission system will have stronger steel
7 poles and larger conductor to provide additional capacity and reduce voltage drop
8 over long distances. The underground subtransmission reliability will improve due
9 to the removal of at-risk or overloaded cables. Additionally, rebuilding the
10 subtransmission system will also remove aging equipment reducing the probability
11 of equipment failures. Furthermore, the rebuilt subtransmission system will be
12 designed to provide redundancy to reduce subtransmission level outages impacting
13 customers.

14

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

21

22 **Q55. What is the scope of the Subtransmission Redesign & Rebuild program?**

23 A55. The subtransmission redesign and rebuild program is focused on installing new
24 station equipment, as well as rebuilding both the overhead and underground
25 portions of the subtransmission system. The station work involves the installation

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1 of large new transformers, capacitor banks and associated equipment, which
2 provides significant improvements to the system with additional redundancy and
3 voltage support. The overhead work will be completed to updated, more resilient
4 standards which include the replacement of aged wood poles with new steel poles,
5 porcelain insulators with polymer clamp top insulators, and smaller and aging
6 conductors with larger wires. The new stronger poles are able to withstand winds
7 up to 90 mph resulting in a much more storm resilient system. The larger wire
8 standard conductor delivers multiple benefits such as providing significantly more
9 capacity on each circuit, reducing the magnitude of voltage drop over long distances
10 on the system, and additionally providing approximately twice the strength of
11 existing conductors to withstand contact with a tree limb during storms or other tree
12 related events. Similar to overhead construction, the underground work consists of
13 replacing at-risk or overloaded cable with new sections and rebuilding cable poles
14 to new standards, supporting greater reliability for both the underground cables
15 themselves, as well as preventing cable failure impacts to adjacent cables in the
16 same underground section of the system.

17

18 **Q56. How did the Company develop the Subtransmission Redesign & Rebuild**
19 **Program?**

20 A56. The Subtransmission Redesign & Rebuild Program was developed to address the
21 identified planning criteria violations and the reliability performance concerns in
22 the subtransmission system. To determine which subtransmission projects would
23 have the greatest impact on reliability and resiliency of the system, the Company
24 reviewed:

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- 1 1) current system planning criteria violations, related to loading and
- 2 voltage challenges;
- 3 2) future distribution system plans and loading projections; and
- 4 3) customer outages caused by subtransmission failures.

5

6 The Company then ranked the planning criteria violations based on severity, and
7 projects were identified that could address the limiting elements on the system.

8

9 The scope of the projects and future subtransmission system configuration also
10 support distribution system conversion plans that include the construction of new
11 higher voltage and retirement of aged lower voltage substations. The distribution
12 system conversion plans provide the necessary input to ensure the scope of the
13 subtransmission projects will meet the requirements of our customers for decades
14 to come.

15

16 In addition to planning criteria violations and future distribution system plans, the
17 Subtransmission Planning engineers monitor the reliability of the system and
18 identify circuits with multiple reliability issues related to subtransmission failures.
19 These circuits are identified, and the subtransmission-related outages are analyzed
20 to determine the most effective project to improve reliability performance. The
21 planning engineers consider both existing routes of the lines that may require
22 rebuilding in place, and sections where multiple wire down events have occurred,
23 which might merit relocation. Based on their analysis, the planning engineers
24 identify which sections to focus on for redesign and rebuild of the lines. The
25 projects that address individual sections of subtransmission include rebuilding to

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1 the current more resilient construction standards and relocating the lines to road
2 accessibility wherever possible.

3

4 **Q57. How does the Company determine priorities when selecting circuits for**
5 **Subtransmission Redesign and Rebuild program?**

6 A57. The company's engineers select circuits for the Subtransmission Redesign and
7 Rebuild program by evaluating system loading and reliability on an annual basis
8 and rank the violations based on severity. DTE Energy considers six criteria when
9 ranking the violations, described in Table 7. The first four criteria are part of what
10 are called planning criteria violations. A planning criteria violation means that in
11 either normal state or single contingency state, the system does not have adequate
12 capacity to serve the existing load without exceeding equipment ratings or voltage
13 standards. Projects are then developed to alleviate the violations.

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Table 7 Subtransmission Priority Criteria

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

2

3 Consistent with other strategic projects and programs, the Subtransmission Rebuild
4 and Redesign projects are prioritized using the GPM which is discussed in detail
5 by Witness Kryscynski.

6

7 **Q58. Can you please describe the Subtransmission Redesign and Rebuild projects**
8 **included in this case?**

9 A58. Table 8 provides the high-level summary of the Subtransmission Redesign and
10 Rebuild projects included in this case. Detailed information for each of these
11 projects is provided in exhibit A-23 schedule M6.

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Table 8 Subtransmission Projects

Project Name	Municipality	Drivers
Ann Arbor System Improvements: State Substation	Ann Arbor	Reliability: The existing distribution system in the Greater Ann Arbor area experiences frequent reliability and power quality issues. Voltage sags and outages are frequent in the area, negatively affecting customers. Capacity: The subtransmission system in Ann Arbor is not adequately sized to accommodate existing load and accelerated load growth in the area. The overloaded system is an impediment to economic growth. Operability: There is currently limited ability to jumper/transfer load to adjacent substations during emergency situations or for routine maintenance. This project, coupled with the other Ann Arbor System Improvements Projects Apex, Argo, and Buckler Circuit Conversions, will address these issues.
Ann Arbor System Improvements: Apex (Blue) Substation	Ann Arbor	Reliability: The existing distribution system in the Greater Ann Arbor area experiences frequent reliability and power quality issues. Voltage sags and outages are frequent in the area, negatively affecting customers. Capacity: The subtransmission system in Ann Arbor is not adequately sized to accommodate existing load and accelerated load growth in the area. The overloaded system is an impediment to economic growth. Operability: There is currently limited ability to jumper/transfer load to adjacent substations during emergency situations or for routine maintenance.
Ann Arbor System Improvements: Argo 40kV Reconfiguration	Ann Arbor	Capacity: Due to high growth in Ann Arbor, ARGO substation does not have capacity to serve downtown Ann Arbor. This is part of the ARGO decommissioning project and will remove Argo from service (see related project Buckler Circuit Conversions).
Transformer High Side Protection Program	Bunce Creek, Chestnut, Newburgh, Northeast, Sunset, Wabash, Hancock, Hines, Pontiac, Spokane, Stephens, Troy, Wayne, Waterman, Wixom	Reliability: Several subtransmission and distribution transformers require the installation of high side protection, either a circuit switcher or breaker, to mitigate observed NERC reportable system issues during simulated contingency conditions that may result in the loss of service to 100+ MVA of customer load. These issues were discovered during annual studies performed by ITC and are required to be mitigated by NERC TPL-001-4 standards.
Subtransmission Redesign & Rebuild: Maxwell Amherst	Detroit	Operability: Amherst industrial substation was partially relocated to Maxwell station during a trouble/emergent job. The drivers for this project is to fully relocate Amherst industrial substation to Maxwell to meet the industrial customer service needs.
Subtransmission Redesign & Rebuild: Trunk 7106	City of Southfield	Capacity: Trunk 7106 is loaded to 134% of the equipment's summer normal rating and 126% of the equipment's summer emergency rating, violating the Subtransmission Planning Criteria. Operability: Load will automatically be shed at Farmington substation to prevent this equipment overload.
Subtransmission Redesign & Rebuild: Trunk 2255	Detroit	Capacity: Trunk 2255 is loaded to 110% of the Summer Emergency rating, exceeding the Subtransmission planning criteria. Operability: Load will automatically be shed at Glendale and Villa substations to prevent this equipment overload.

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Table 8 Subtransmission Projects, Continued

Project Name	Municipality	Drivers
Subtransmission Redesign & Rebuild: Trunk 2237-ST	Redford	Capacity: Trunk 2237 is loaded to 100% of the equipment's summer normal rating and 110% of the equipment's summer emergency rating, violating the Subtransmission planning criteria. Operability: There is an Emergency Load Control scheme at Six Mile Substation that will automatically shed load (10.3 MVA) to prevent from overloading equipment on Trunk 2237 and protect the equipment from any permanent damage
Subtransmission Redesign & Rebuild: Kennett	Madison Heights	Capacity: Trunk 7333 is loaded to 129% of the summer normal rating and 126% of the summer emergency rating, exceeding the Subtransmission planning criteria. Operability: Load will automatically be shed at Brazil & Kenney substations to prevent this equipment overload.
Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker	Sandusky	Capacity: Sandusky Transformer 101 is loaded to 126% of the equipment's summer normal rating, violating the Subtransmission Planning Criteria.
Subtransmission Redesign & Rebuild: Boyne	Macomb, Harrison, Clinton, Mt. Clemens, Chesterfield, New Baltimore	Capacity: Trunk 7909 is loaded to 120% of its summer emergency rating, violating the Subtransmission Planning Criteria. Operability: Load will be automatically shed at Omega and Beach Substations to prevent this equipment overload.
Subtransmission Redesign & Rebuild: Tie 4105	Lexington, Croswell, Port Sanilac, Applegate, Carsonville	Reliability: TIE 4105 has experienced frequent outages, escalated complaints, and is one of the worst performing Subtransmission lines.
Subtransmission Redesign & Rebuild: Tie 1568	Ypsilanti	Capacity: Tie 1568 is loaded to 99% of the equipment's summer emergency rating, exceeding the Subtransmission planning criteria. Operability: Load will automatically be shed at Crown substation to prevent this equipment overload.
Subtransmission Redesign & Rebuild: Trunk 4217	Grosse Pointe, Harper Woods & Detroit	Capacity: Trunk 4217 is loaded to 123% of the equipment's summer normal rating and 116% of the equipment's summer emergency rating, exceeding the Subtransmission planning criteria. Operability: Load will automatically be shed at Grosse Pointe and Vernier substations to prevent this equipment overload.
Subtransmission Redesign & Rebuild: Trunk 3509	Troy City Shelby SC Territory	Capacity: Trunk 3509 is loaded to 100% of the equipment's summer normal rating and 109% of the equipment's summer emergency rating, violating the Subtransmission Planning Criteria. Operability: Load will automatically be shed at Patton Substation to prevent this equipment overload.
Subtransmission Redesign & Rebuild: Trunk 4266	East Pointe	Capacity: Trunk 4266 is loaded to 108% of the equipment's summer emergency rating, violating the Subtransmission Planning Criteria. Operability: Load will automatically be shed at Savoy Substation to prevent this equipment overload.
Subtransmission Redesign & Rebuild: Praxair	301 E Great Lakes Ave, River Rouge	Operability: The normally open section disconnect at Praxair Substation is not rated high enough to interrupt the transformer load. Therefore, the customer's operation need to be interrupted everytime the switch need to be operated. The number of shutdowns currently required for DTE maintenance activities greatly impacts the primary customer's business and coordination of this work is challenging.
Subtransmission Breaker Short Circuit Violations	Bad Axe, Taylor, East Pointe, Detroit, Royal Oak, Milford, Warren, & Monroe	Safety/Reliability: 20 breakers on the Subtransmission system are in violation of the Subtransmission Planning criteria by exceeding their interrupting ratings. This could result in equipment damage or catastrophic failure of these breaker positions.
Subtransmission Redesign & Rebuild: Slocum	Trenton	Other: The Trenton Channel Power Plant, including all outlying structures and buildings are planned for retirement in 2022 with subsequent demolition. 3 trunk lines will be redesigned to remove all unused equipment that is currently being used to feed system service transformers at the power plant.
Subtransmission Redesign & Rebuild: 40kV Capacitor Banks at Armada and Adair	Macomb and St. Clair Counties Shelby and Marysville SC Territories	Capacity: Tie 810 is a three-ended tie line consisting of 50 miles of overhead lines serving 10 substations. Low voltage levels are currently seen on this circuit due to significant circuit mileage and load.
Subtransmission Redesign & Rebuild: Oak Beach Capacitor	Port Austin	Capacity: Oak Beach and Caseville substations experience low voltage violations for an outage on Tie 3205, violating the Subtransmission Planning Criteria. Operability: The System Operations Center restricts shutdowns on Tie 3205 to prevent this low voltage. During an outage, manual load shed would be return the voltage to our operating limits.

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Table 8 Subtransmission Projects, Continued

2

Project Name	Municipality	Drivers
Subtransmission Redesign & Rebuild: Tie 810 (Gramer)	Macomb and St. Clair Counties Shelby and Marysville SC Territories	Capacity: Tie 810 experiences low voltages in multiple single contingency scenarios, which violates the Subtransmission planning criteria. Tie 810 experiences overloads in multiple single contingency scenarios. Operability: Load will automatically be shed at various substations to prevent this equipment overload.
Subtransmission Redesign & Rebuild: Tie 7504	Novesta Twp	Reliability: Customer complaints and escalations have been received due to frequent outages on TIE7504. Capacity: Substations served from TIE7504 experience low voltage during a single contingency, violating the Subtransmission Planning Criteria. Operability: 7 MVA of load is automatically shed on TIE7504 to prevent low voltage.
Subtransmission Redesign & Rebuild: Trunk 2308	Macomb	Capacity: Trunk 2308 is loaded to 99% of its summer emergency rating, exceeding the Subtransmission planning criteria. Operability: Load will automatically be shed at Benson Substation to prevent this equipment overload.
Subtransmission Redesign & Rebuild: Tie 3205	Pigeon, Caseville, Oak Beach, Port Austin	Reliability: TIE3205 has experienced frequent outages. This tie line is one of the worst performing circuits and it does not meet current design standards.
Subtransmission Redesign & Rebuild: Reverse Power Relay Scheme Program	Ann Arbor, Bad Axe, Chelsea, Commerce TWP, Fostoria, Grant TWP, Harbor Beach, Highland Park, Madison Heights, Monroe, Lenox, Rochester Hills,	Station locations do not have appropriate equipment to prevent backfeed onto the transmission system. Not having this equipment additional operating actions need to be take place creating additional work on DTE's side for switching, often reduces system reliability, and frequently can introduce additional restrictions on much needed shutdowns. This has resulted in ITC Operations requesting DTE to install reverse relay schemes at various locations.
Subtransmission Redesign & Rebuild: Tie 4104 North	Sherman and Sand Beach Townships	Reliability: TIE4104 has experienced frequent outages and deterioration of the conductor has been identified from testing.
Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition	Bad Axe	Capacity: The tielines out of Bad Axe station experience low voltage violations for the loss of Bad Axe Transformer 101, violating the Subtransmission Planning Criteria. Operability: The System Operations Center restricts shutdowns on Bad Axe Transformer 101 to prevent this low voltage. During an outage, manual load shed up to 23.4 MVA would be return the voltage to our operating limits.
Subtransmission Redesign & Rebuild: Trunk 4245	Eastpointe	Reliability: The conduit crossing I-94 at 9 mile is damaged causing cable to become stuck in the ducts. Shores substation is at risk of losing their subtransmission feeds if cable failures occur.
Subtransmission Redesign & Rebuild: Trunk 4911	Lenox Twp. Chesterfield Twp. City of New Baltimore Ira Twp.	Capacity: Trunk 4911 experienced multiple overloads in a normal and emergency scenario up to 130% of the equipment rating, violating the Subtransmission Planning Criteria. Trunk 4911 also experienced low voltages in multiple emergency scenarios, violating the Subtransmission Planning Criteria. Operability: Load will be automatically shed at New Baltimore and Chesterfield substations to prevent equipment overload.
Subtransmission Redesign & Rebuild: Custer Republic	Monroe	Operability: Transformer 3 at Republic substation is 71 years old and carrying no load. Breaker equipment at Custer 68 years old. Reconfiguring the trunk lines between Custer and Republic will allow these under-utilized assets to be decommissioned.
Station Upgrade: Cortland Station Expansion	Highland Park	Reliability: Cortland Station was identified as a high-risk station in the Operational Risk Assessment. Operability: The existing station transformers at Cortland have physical constraints that do not allow for replacement in their existing locations. If a transformer failure were to occur, there are minimal options to serve the load if the next contingency were to occur. Many portable generators would be required.

3

4 **Q59. What is the Subtransmission Small Projects and Reserve Program?**

5 A59. There are times when the Company experiences issues on the subtransmission
6 system that are less complex, and that unlike the larger subtransmission projects

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1 can be executed without extensive engineering and planning. These projects are
2 generally smaller in scope and level of investment, requiring \$500,000 or less in
3 capital. The typical scope of work for these projects addresses thermal or voltage
4 violations, under either normal or single contingency situations. Projects of this
5 nature are identified during the yearly engineering analysis, which is the same
6 methodology used to identify all the subtransmission projects under the
7 Subtransmission Redesign and Rebuild program. Because the Company
8 experiences this type of situation every year and they can be solved quickly without
9 extensive engineering and planning, the Company has created a Small Projects and
10 Reserve program. This program allows the Company to address these less complex
11 issues on the subtransmission system in a short amount of time, without the more
12 involved planning and engineering required for a larger, more extensive project. A
13 high-level summary of these projects for 2024 is provided in Table 9

14

15 **Table 9 Projects in the Small Projects and Reserve Program**

Project ID	Municipality	Drivers
TRK 2508	Warren	Capacity: Trunk 2508 is loaded to 98% of its emergency rating, exceeding the Subtransmission planning criteria. Operability: Load will automatically be shed at Centerline substation to prevent this equipment overload.
TRK 2506	Warren	Capacity: Trunk 2506 section is loaded to 98% of its emergency rating, exceeding the Subtransmission planning criteria. Operability: Load will automatically be shed at Centerline substation to prevent this equipment overload.
Trunk 7114 -7115	Southfield	Capacity: Trunk 7114-7115 is loaded to 120% of its emergency rating, exceeding the Subtransmission planning criteria. Operability: Load will automatically be shed at Sargent and Gary substations to prevent this equipment overload.

16

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1 **Q60. How do customers benefit from the Small Projects and Reserve program?**

2 A60. Similar to other subtransmission projects, the Small Projects and Reserve program
3 will provide multiple customer benefits including safety, improved reliability and
4 operability, and increased capacity, but within a shorter period of time due to the
5 much more limited scope and compressed schedule required to address identified
6 system issues. With the ability to address the system conditions and provide more
7 immediate benefits to the customers with a relatively quick solution, the projects
8 are executed shortly after identification instead of following the more structured
9 project management steps of a larger project.

10

11 Strategic Undergrounding Program

12

13 **Q61. Why is the Company interested in the undergrounding of circuits as part of**
14 **conversion projects?**

15 A61. The combination of aged overhead infrastructure and increasingly frequent and
16 severe storms has resulted in negative reliability impact for many of our customers.
17 A frequent question from our customers and other stakeholders in response to
18 frequent outages has been “why not underground the lines?”. The Company is
19 interested in making undergrounding a viable option when circuits are being
20 converted as that is the optimum time to take advantage of the synergy of the
21 rebuilding process instead of just replacing the existing overhead infrastructure.

22

23 Undergrounding protects the electrical infrastructure from increased storm
24 frequency and severity, thus providing resiliency and improving reliability. An
25 undergrounded circuit also has safety advantages since there are no downed wires

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1 during storm events. Furthermore, over the life cycle of the assets, undergrounding
2 can provide the benefit of reduced maintenance and repair costs due to eliminating
3 the need for tree trimming, pole top maintenance, and in most storm cases, trouble
4 response.

5

6 Through benchmarking, the Company has learned that many other utilities are also
7 pursuing undergrounding of their existing overhead lines as a means to harden their
8 systems for greater resiliency, increase reliability, and improve storm response.

9

10 To take advantage of this unique opportunity to be able to underground larger
11 portions of the new converted system, the Company plans to conduct pilot projects,
12 and initially seek out areas where there are construction synergies, which could be
13 achieved by jointly working with municipalities or other utilities. This approach
14 will allow the Company to learn, develop best processes for undergrounding in
15 mature urban, suburban, and rural areas while focusing on reducing implementation
16 cost. These pilot projects will also allow the Company to further demonstrate the
17 benefits of undergrounding and determine when/where this design choice can be
18 applied effectively.

19

20 **Q62. How do the Strategic Undergrounding pilot projects differ from the**
21 **Company's existing underground infrastructure and undergrounding that is**
22 **done in new developments?**

23 A62. The Company has been implementing underground residential distribution (URD)
24 infrastructure since the 1970s for new construction subdivisions. Furthermore, the
25 Company has a vast underground cable system utilizing the typically manhole

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1 construction in the city of Detroit and other urban areas in its service territory.
2 Combined, over 30% of the Company's electric system is already underground.
3 However, the Company has limited experience undergrounding existing overhead
4 electrical infrastructure as part of the conversion process in mature and developed
5 urban, suburban, and rural areas of the distribution grid. The rebuilding of existing
6 overhead infrastructure to underground is significantly different in scope than
7 installing underground infrastructure in a new development.

8
9 To learn and gain experience on undergrounding of existing overhead
10 infrastructure, the Company is implementing undergrounding pilot projects. The
11 main object of the pilot projects is to understand the challenges of undergrounding
12 in a mature urban setting, define scenarios and situations when undergrounding can
13 reap of rewards of safety, reliability, and resiliency benefits, and refine
14 underground construction processes to gain cost efficiency on the installation. An
15 additional goal is to analyze the longer-term benefits of undergrounding, to better
16 support a refined benefit-to-cost analysis in the future.

17

18 **Q63. Has the Company piloted undergrounding existing overhead lines?**

19 A63. Yes. Per case U-20169, the Company was asked to explore potential pilot projects
20 to eliminate rear-lot overhead infrastructure and its associated hazards. With the
21 focus on reducing the safety hazards associated with rear-lot infrastructure, the
22 Company initiated a pilot project on Appoline DC1346 (Appoline) in Detroit to
23 move rear-lot overhead assets to rear-lot underground infrastructure, including the
24 service lines. Appoline pilot project included 61 residential customers on two city
25 blocks in Detroit. The scope of this pilot project included installation of

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1 approximately 1,300 feet of primary cable, six transformers, and underground
2 services to residences.

3

4 **Q64. What were the objectives of the Appoline pilot project?**

5 A64. The objectives of the Appoline pilot project were to assess the safety improvements
6 of undergrounding rear-lot overhead infrastructure, gather information on actual
7 installation costs of undergrounding in a mature rural neighborhood, understand
8 customer acceptance, and determine opportunities to improve cost and construction
9 efficiency.

10

11 **Q65. What was the timing of the Appoline undergrounding pilot project?**

12 A65. The Company began engineering for the Appoline pilot project in 2018 and
13 construction started in 2019. The Company initially had challenges with clearing
14 rear alley structures and debris to gain access to the distribution infrastructure, and
15 then ran into challenges with getting approvals from owners of rental properties as
16 well as challenges posed by the Pandemic, delaying the final construction of a small
17 number of customer service lines. The pilot project was completed in October 2023
18 with all customers converted to underground service and all related overhead
19 infrastructure decommissioned. After internal benchmarking with DTE Gas, the
20 Company took a more direct approach to connect all customers via an
21 undergrounded service.

22

23 **Q66. What were the lessons learned from the Appoline underground pilot project?**

24 A66. From the Appoline pilot project, the Company gained valuable experience in
25 undergrounding existing overhead infrastructure in a mature urban neighborhood.

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1 With all overhead customer services undergrounded and the removal of rear lot
2 overhead lines, the associated safety hazards of rear lot overhead lines were
3 eliminated for this area. Additional learnings were that early customer engagement
4 prior to construction is critical for success. The Company had difficulty in
5 contacting the homeowners, often landlords at remote locations instead of onsite
6 residents, to obtain approvals required to modify the electric service attachments to
7 their homes. Before installation work could begin, the overhead infrastructure
8 located in rear alleyways required extensive vegetation and debris removal.
9 Furthermore, routing underground services from the rear-lot was very challenging
10 due to garages, patios, and other customer obstructions that have accumulated from
11 decades of neglect. Essentially every customer required a unique route to
12 underground their service. Exhibit A-23 Schedule M11 provides detailed
13 information for the Appoline pilot. Due to these challenges, the schedule, and the
14 cost for the Appoline pilot were negatively impacted.

15

16 **Q67. Was a benefit-to-cost analysis (BCA) completed for the Appoline pilot**
17 **project?**

18 A67. Yes. An initial BCA for the Appoline pilot project based on a partial subset of
19 customer installations was presented in the MPSC case U-21297, however it was
20 inconclusive due to limited customer data. Since that time, the Company
21 collaborated with an independent consulting firm to create an updated BCA based
22 on methodology utilized by other utilities in other states (such as IN, OH, IL, MD,
23 FL, and OK). This analysis uses a long-term, present value methodology to
24 compare the customer and utility benefits to the costs associated with investment
25 options. The Appoline underground pilot project was compared with the

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1 alternatives of PTMM and overhead rebuild. The benefits of the Appoline
2 underground pilot project included the present value of the avoided future costs of
3 vegetation management, PTMM, and emergent reactive events. The model also
4 included the benefits associated with the customer impacts of outages, using the
5 Lawrence Berkeley National Laboratory (LBNL) Interruption Cost Estimate (ICE)
6 calculator. The LBNL ICE calculator is used by many utilities to approximate
7 customers' costs of interruptions, although many including LBNL acknowledge
8 that the model is conservative and underestimates the true costs of the outages.
9 Then a benefit-to-cost ratio (BCR) was calculated for each investment option and
10 compared to alternatives. The detailed BCA for the Appoline pilot is provided in
11 Exhibit A-23 Schedule M13.

12

13 **Q68. What were the results from the BCA for the Appoline pilot project?**

14 A68. This analysis indicated that the BCR of the Appoline pilot project was lower than
15 the overhead rebuild, but higher than PTMM. In this analysis a higher BCR
16 indicates that there are more benefits than cost as a ratio, so either higher estimated
17 benefits or lower costs of the project can raise the ratio. As this was an initial pilot
18 project with initial learnings that included the substantial costs to remediate rear
19 alley debris, this pilot BCR was not unexpected. Several factors contributed to the
20 lower Appoline BCR. As discussed earlier and in Exhibit A-23 Schedule M11,
21 there were challenges in getting approval from all the customers, in particular non-
22 resident landlord owners. This delayed the project completion and caused
23 additional mobilization and demobilization costs. Furthermore, to connect each of
24 the customers' service from the rear-lot underground infrastructure required a
25 unique design and process for each customer, adding additional cost for this pilot.

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1 Adding on the cost for vegetation and debris removal to implement this pilot, these
2 challenges further impacted the project cost. These specific learnings have been
3 included in subsequent undergrounding work.

4

5 **Q69. Are there additional important benefits that are not included in the BCA for**
6 **the Appoline pilot project?**

7 A69. Yes. Significant benefits of safety and resiliency for customers are not included in
8 the financial BCR of the Appoline pilot project. With the rear lot overhead 4.8 kV
9 conductors removed, the wire down hazard for this section of the distribution circuit
10 has been eliminated. Furthermore, by undergrounding the overhead lines, the
11 community and the customers also reaped the significant benefit of greater
12 resiliency against the more frequent and more severe extreme weather events that
13 could lead to prolong outages. The ICE Calculator described earlier, although
14 meant to capture the benefit of incremental reliability, “may not accurately reflect
15 current interruption costs, given that around half of the data in the meta-database is
16 from surveys that are 15 or more years old. To address this issue, the 2009 study
17 included an intertemporal analysis, which suggested that interruption costs did not
18 change significantly throughout the 1990s and early 2000s. However, during the
19 past decade in particular, technology trends may have led to an increase in
20 interruption costs. For example, home and business life has become increasingly
21 reliant on data centers and “cloud” computing, which may have led to an increase
22 in interruption costs for both producers and consumers of these services. Therefore,
23 the outdated vintage of the data presents concerns that underscore the need for a
24 coordinated, nationwide effort that collects interruption cost estimates for many
25 regions and utilities simultaneously, using a consistent survey design and data

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1 collection method.”⁴ Both of these benefits, safety and resiliency, are not easily
2 quantifiable in a way that matches present day customer needs or impacts. The
3 Company will continue to collaborate with the MPSC and industry stakeholders to
4 determine an appropriate way to quantify these benefits.

5

6 **Q70. Is the Company pursuing other strategic undergrounding pilot projects?**

7 A70. Yes. By collaborating closely with the city of Detroit, the Company developed a
8 project to underground portions of the STLUS DC116 circuit in the Buffalo-
9 Charles neighborhood. This is a bold initiative to underground approximately four
10 miles of residential distribution lines using front-lot construction in a mature urban
11 neighborhood with the intent of capturing additional benefits of joint gas and
12 electric work.

13

14 **Q71. Why was Buffalo-Charles neighborhood selected as the next underground**
15 **pilot project?**

16 A71. The Company considered multiple criteria in the selection process for the next
17 undergrounding pilot. Selection criteria included wire downs per mile (safety),
18 sustained and momentary outages for the circuit (reliability), impact to the
19 community (energy justice), and construction cost. Over several meetings with
20 City of Detroit officials, DTE Gas, and internal subject matter experts, six Detroit
21 neighborhoods were reviewed and analyzed. The Buffalo-Charles neighborhood
22 was very comparable with the other five areas that were evaluated. However, the
23 Buffalo-Charles neighborhood was additionally attractive because it allowed the

⁴ Sullivan, M.J., J. Schellenberg and M. Blundell (2015). Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States. Lawrence Berkeley National Laboratory Report No. LBNL-6941E, pg. 18

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1 Company the opportunity to work with DTE Gas, who are also doing underground
2 gas main work in many areas of the city. Collaborating with DTE Gas will allow
3 DTE Electric an opportunity to achieve synergies in the construction process to
4 explore opportunities for further cost reductions and construction efficiency in co-
5 located projects. By jointly working with DTE Gas, DTE Electric can utilize the
6 same contractor for construction synergies that can lower the cost of the project.
7 Furthermore, this is a benefit for customers in the project area, since gas main
8 replacement and electrical infrastructure undergrounding is done at the same time,
9 resulting in less disruption and impact on the neighborhood as compared with two
10 separate projects at different times.

11

12 **Q72. How has the Company engaged customers and other stakeholders in the**
13 **Buffalo-Charles pilot project?**

14 A72. Throughout the inception of this project, DTE has worked closely with the City of
15 Detroit Mayor's office, City council, and other infrastructure partners. Per exhibit
16 A-28 Schedule R1, the City of Detroit Mayor's office is very supportive of this
17 undergrounding pilot because it will improve the quality of life for its residents
18 through improved safety, resiliency, and reliability.

19

20 Once the specific project location was confirmed, a community town hall was held
21 on September 13, 2023, at the Lasky Recreation Center. During this community
22 town hall meeting, the company provided in-person communications with all
23 customers and stakeholders to explain the scope and expectations of the project.
24 Door to door communications preceded the town hall to let members of the
25 community know about the project and to invite them to the event. Additional

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1 communications have also occurred throughout the construction including blog
2 posts, direct mailings, and door hangers.

3

4 **Q73. What is the scope of the Buffalo-Charles project?**

5 A73. The scope is to underground portions of the STLUS DC1136 circuit in the Buffalo-
6 Charles neighbor of Detroit to 13.2 kV capable front-lot underground residential
7 distribution infrastructure and remove the aged 4.8 kV overhead rear-lot
8 distribution equipment. In relocating to front-lot construction, the scope of
9 undergrounding Buffalo-Charles is an enhancement from the rear-lot scope of
10 Appoline. As the industry has evolved, peer utilities have adopted to use accessible,
11 front-lot URD construction for undergrounding in an urban environment.
12 Furthermore, front-lot URD has the potential for reduce construction cost.

13

14 The scope for the Buffalo-Charles pilot included constructing 3.9 miles of
15 underground residential distribution to service 459 customers using front-lot
16 construction. This project will install 4.3 miles of primary conduit, 3.9 miles of
17 underground primary cable, 4.5 miles of underground secondary cable, and 8.9
18 miles of service cable. Additionally, this project will install 48 pad-mounted
19 transformers, 153 secondary handholes, 459 junction boxes, 31 cable poles, and 12
20 ISO-UP transformers. Furthermore, this project will remove 2.8 miles of overhead
21 primary, 3.5 miles of overhead secondary, 459 overhead services, and 3.5 miles of
22 PLD/ARC wire.

23

24 **Q74. What is the timing of the Buffalo-Charles project?**

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1 A74. After meeting with stakeholders throughout the summer of 2023, engineering and
2 design were completed in late fall of 2023, with construction beginning in late
3 October. The Buffalo-Charles project is expected to be completed by end of 2024.
4

5 **Q75. Did the Company conduct a BCA for the Buffalo-Charles project?**

6 A75. Yes. The Company used the same approach to conduct the BCA for Buffalo-
7 Charles as it did for the Appoline pilot as described above. The detailed BCA for
8 the Buffalo-Charles is provided in Exhibit A-23 Schedule M13.
9

10 The BCR results for Buffalo-Charles were similar to Appoline in that it was lower
11 than the overhead rebuild, but nearly equivalent to PTMM. As with the Appoline
12 BCR, the Buffalo-Charles project BCR result was not unexpected, given that the
13 Company is still in the early stage of undergrounding pilots. Several factors
14 contributed to the lower Buffalo-Charles BCR. The analysis used an initial cost
15 estimate for implementing front-lot underground infrastructure in a mature urban
16 neighborhood while removing old rear-lot overhead construction. The Company
17 believes that actual project costs may come in lower with rigorous project
18 management and the realization of project efficiencies with greater pilot experience.
19

20 **Q76. Are there additional important benefits that are not included in the BCA for**
21 **the Buffalo-Charles pilot project?**

22 A76. Yes. Similar to the Appoline pilot project, significant benefits of safety and
23 resiliency for customers are not included in the financial BCR of the Buffalo-
24 Charles pilot project. When the rear lot overhead 4.8 kV conductors will be
25 removed, the wire down hazard for this section of the distribution circuit will be

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1 eliminated. Furthermore, by undergrounding the overhead lines, the community
2 and the customers will reap the significant benefit of greater resiliency against the
3 more frequent and more severe extreme weather events that could lead to prolong
4 outages. The ICE Calculator described earlier, although intended to capture the
5 benefit of incremental reliability, “may not accurately reflect current interruption
6 costs, given that around half of the data in the meta-database is from surveys that
7 are 15 or more years old. To address this issue, the 2009 study included an
8 intertemporal analysis, which suggested that interruption costs did not change
9 significantly throughout the 1990s and early 2000s. However, during the past
10 decade in particular, technology trends may have led to an increase in interruption
11 costs. For example, home and business life has become increasingly reliant on data
12 centers and “cloud” computing, which may have led to an increase in interruption
13 costs for both producers and consumers of these services. Therefore, the outdated
14 vintage of the data presents concerns that underscore the need for a coordinated,
15 nationwide effort that collects interruption cost estimates for many regions and
16 utilities simultaneously, using a consistent survey design and data collection
17 method.”⁵ Both of these benefits, safety and resiliency, are not easily quantifiable
18 in a way that matches present day customer needs or impacts. The Company will
19 continue to collaborate with the MPSC and industry stakeholders to determine an
20 appropriate way to quantify these benefits.

⁵ Sullivan, M.J., J. Schellenberg and M. Blundell (2015). Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States. Lawrence Berkeley National Laboratory Report No. LBNL-6941E, pg. 18

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1 **Q77. How do the Company's undergrounding pilot projects' scope compare to**
2 **other utilities that it benchmarked?**

3 A77. Many benchmarked utilities are undergrounding as a means to make their grid safer
4 and more resilient to increased frequency and severity of weather events. However,
5 the scope of utility undergrounding varies based upon the utility strategy and
6 geography. Several utilities in the West are undergrounding in and around defined
7 high fire risk areas. The majority of these identified fire risk areas are in rural, less
8 densely populated areas. Similarly, many of the utilities benchmarked in the South
9 and Midwest are undergrounding in rural parts of their territory to improve storm
10 response time and to improve their reliability metrics. The typical construction
11 method used is trenching in road right of way and then either direct bury the cables
12 or use conduit. With many of the utilities leaving the customer services overhead.
13 DTE is one of the few utilities that is undergrounding in dense urban environments.

14

15 **Q78. Why is the Company choosing to pilot undergrounding in dense urban**
16 **environments?**

17 A78. The main reasons that an urban environment was selected was based on the priority
18 of safety, eliminate the hazards associated with 4.8 kV ungrounded delta system
19 rear-lot construction, and to improve storm response for resiliency by reducing the
20 number of customer services down. To achieve these objectives, the construction
21 method utilized is to bore conduit for primary and secondary connections instead
22 of trenching. To improve storm response and resiliency for single customer
23 outages, often of longer duration in a large storm, the Company is also
24 undergrounding customer service drops. These factors of the urban dense customer
25 environment and undergrounding customer services will result the Company's

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1 undergrounding costs being higher when compared with another utility's scope of
2 implementing in a rural environment without service drop replacement.

3

4 **Q79. Is the Company considering additional undergrounding pilot projects?**

5 A79. Yes. The Company believes that undergrounding brings a set of unique benefits
6 and is of high interest to our customers. Undergrounding is the only investment
7 option that eliminates the safety risk associated with downed wires and structures.
8 Undergrounding provides the highest overall benefit in reducing emergent reactive
9 costs and customer outages. Undergrounding is the most resilient option for severe
10 weather-related events. Due to these advantages of undergrounding, the Company
11 believes that it needs to conduct additional pilots to continue to learn and focus on
12 reducing implementation costs, to increase the overall benefit to cost ratio.

13

14 The future projects are planned to involve a mix of geography; urban, suburban, and
15 rural. Learnings from these projects will be used to refine the current benefit cost
16 models to help identify segments of overhead infrastructure that are good candidates
17 for undergrounding. This approach will allow the Company to develop a cost
18 competitive undergrounding program.

19

20 Primary Deconductoring

21

22 **Q80. What is Primary Deconductoring?**

23 A80. Primary Deconductoring is the removal of unneeded or underutilized infrastructure
24 such as aged small-sized primary wire, PLD arc wire, overhead transformers, and

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1 other pole top equipment in abandoned or blighted neighborhoods in the city of
2 Detroit.

3

4 **Q81. What are the benefits of Primary Deconductoring ?**

5 A81. The benefit of removing overhead lines that are not fully utilized, and any
6 associated arc wire, reduces wire downs and improves safety in that area.
7 Removing unnecessary overhead lines also eliminates the potential for power
8 outages caused by those lines failing or being damaged thus improving reliability
9 in the area. In some situations, primary deconductoring may require the installation
10 of new secondary lines to serve the few remaining homes in the neighborhood.
11 When new secondary lines are installed, they are constructed to the current
12 standards.

13

14 **Q82. What is the scope of work for Primary Deconductoring?**

15 A82. The scope of work for Primary Deconductoring includes the removal of unneeded
16 or underutilized infrastructure such as aged small-sized primary wire, abandoned
17 arc wire, OH transformers, and other pole top equipment in abandoned or blighted
18 neighborhoods. In addition, where necessary the Company will reconductor
19 secondary wires and upgrade transformers and other pole top equipment, and where
20 possible install equipment in truck accessible locations.

21

22 **Q83. Has the Company completed the Primary Deconductoring pilot?**

23 A83. The Company has completed pilots on two circuits in 2023. In Case No. U-21297,
24 the Commission approved \$1.8M of investment in 2022. The Company had an
25 additional 36,000 of investment in 2023 to complete these two pilots.

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1 **Q84. How is Primary Deconductoring used as part of current circuit planning?**

2 A84. Per the success of the two completed pilots, the Company has rolled primary
3 deconductoring into the 4.8 kV Hardening program and 4.8 kV Conversion
4 projects, were applicable.

5

6 System Loading Projects

7

8 **Q85. Can you describe a system overload?**

9 A85. System overloads occur on a circuit or substation when there is insufficient capacity
10 to meet customer demands while maintaining grid operation within equipment
11 operating ratings. Capacity needs are analyzed for two conditions: normal state and
12 contingency state. The normal state exists when all equipment and components are
13 in service and operating as designed. The contingency state exists when there is
14 either a temporary, planned equipment shutdown or the unplanned loss/failure of a
15 component of the electric power system (e.g., transformer, cable, or breaker). Under
16 contingency state conditions, equipment in the rest of the system may see an
17 increase in loading to compensate for the out-of-service equipment, delivering
18 additional power above normal state.

19

20 To meet the two capacity needs of the system, most components and equipment have
21 two ratings: day-to-day and emergency. These ratings are calculated to maintain the
22 viability of an asset throughout its expected useful life. Operating equipment above
23 its designated ratings can cause immediate failure or accelerate end-of-life and is
24 considered an overload. DTE definitions for day-to-day rating, emergency rating,

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- 1 and substation firm rating are consistent with industry definitions such as those
- 2 available from National Electrical Reliability Corporation⁶,
- 3 • The day-to-day rating (for normal state conditions) is the load level at which
 - 4 the equipment can be operated for its expected life span.
 - 5 • The emergency rating (for contingency state conditions) is typically higher
 - 6 than the day-to-day rating and indicates the load level that the equipment
 - 7 can operate for short periods of time only. Operating towards the emergency
 - 8 rating adds stress to the equipment and may shorten its lifespan. If a piece
 - 9 of equipment exceeds its emergency rating, the Company's ESOC
 - 10 personnel will take immediate steps to transfer load or shed load if
 - 11 necessary.
 - 12 • Substations also have a firm rating, which is the maximum load the
 - 13 substation can carry under a single contingency condition and is based on
 - 14 the lowest emergency rating of any substation equipment that is required to
 - 15 serve the load; such as incoming subtransmission feed, transformer, and
 - 16 secondary cables. Figure 13 below shows an illustration of a substation
 - 17 with a firm rating of 45 MVA. The substation consists of 2 transformers.
 - 18 Transformer 1 has an emergency rating at 45MVA and transformer 2 has
 - 19 an emergency rated at 50 MVA. Transformer 1 has the lowest emergency
 - 20 rating of the equipment inside the substation, therefore 45 MVA is the firm
 - 21 rating of the substation in this example. Under normal operation both
 - 22 transformers serve customer load that they are designed to serve. In a single
 - 23 contingency situation, such as the failure of a transformer or loss of a

⁶ Glossary of Terms Used in NERC Reliability Standards, available at https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf, accessed March 12, 2024

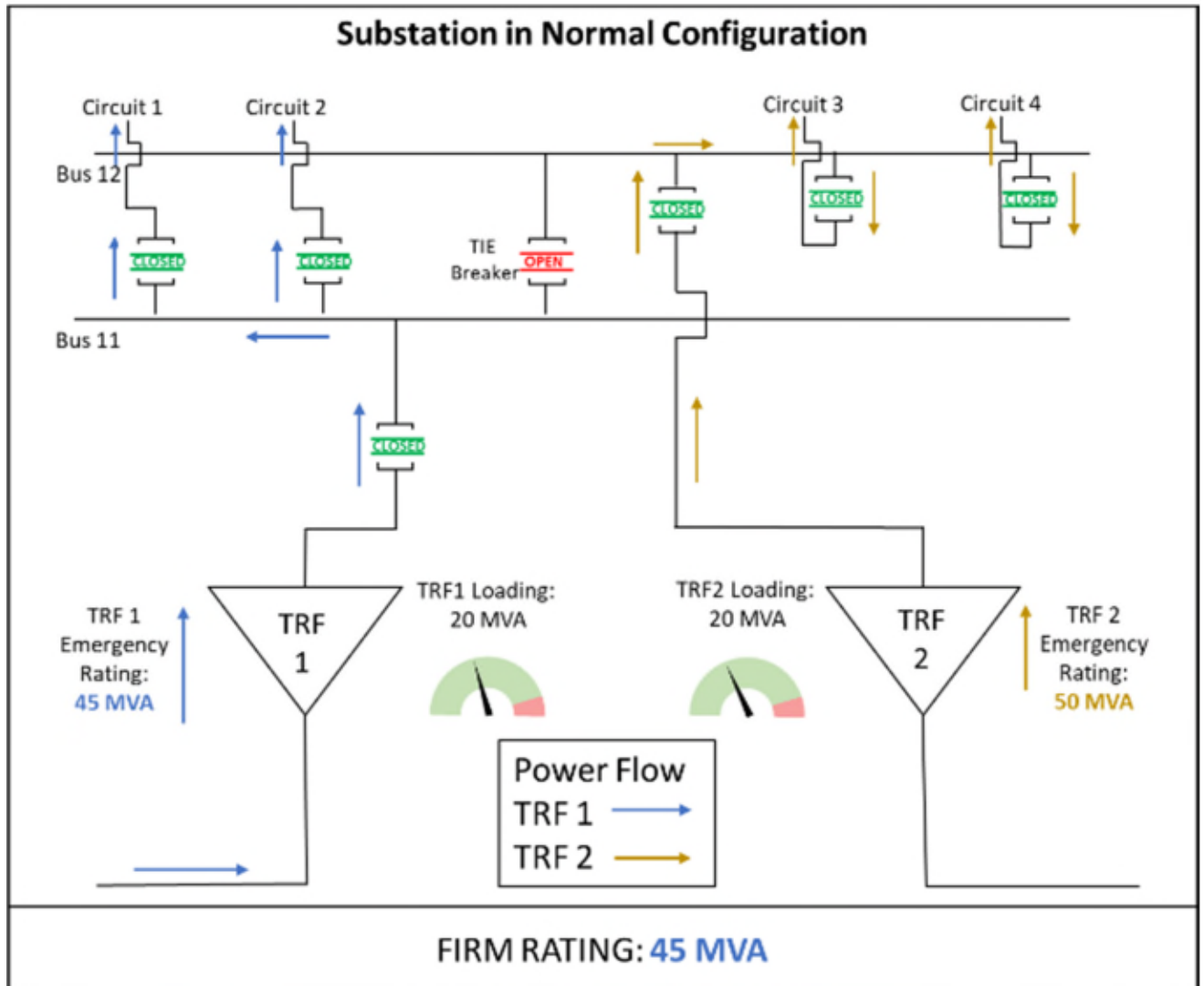
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1 subtransmission feed, automatic operations will occur within the substation
2 and customer load will continue to be served to avoid a large, sustained
3 outage. Figure 14 below shows the same substation operating in a single
4 contingency situation where transformer 2 is down. Transfer 2 breaker is
5 opened to isolate and deenergize it. The tiebreaker is closed to allow
6 customer load to be rerouted through transformer 1. The total load on the
7 substation is below firm rating so all the customers can be fed from
8 transformer 1. If the total load on the substation is over the firm rating, the
9 extra load on transformer 1 would cause it to operate above its emergency
10 rating. Typically, the Company does not operate its equipment at or above
11 emergency ratings. To prevent operating at or over emergency rating, the
12 loading on Trans 1 would need to be reduced. This would require load to be
13 shed and customers would experience an outage until the situation is
14 remediated.

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Figure 13 Substation in Normal Configuration



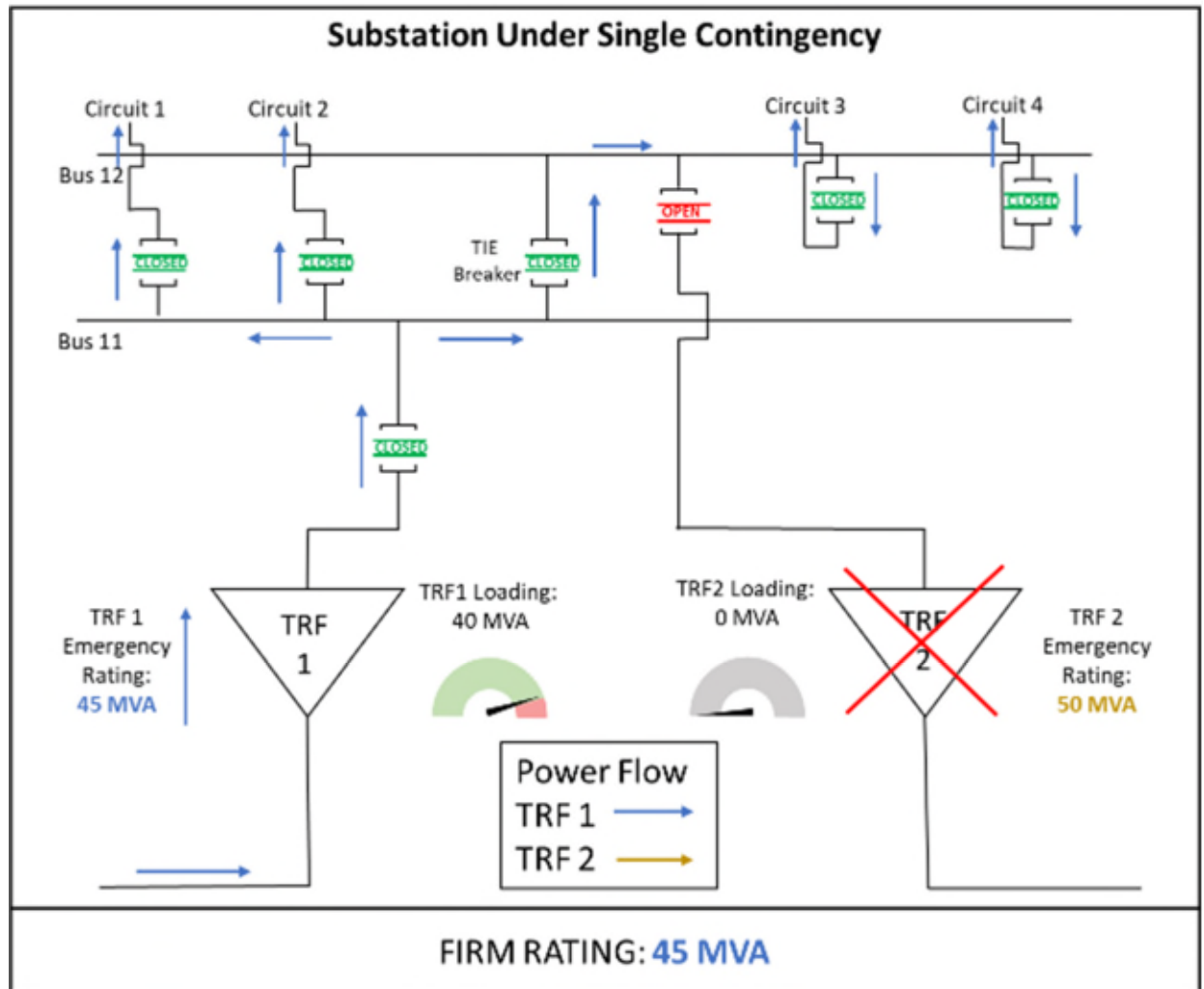
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Figure 14 Substation under Single Contingency

2



3

4 **Q86. What are the challenges and issues with system overloads?**

5 A86. When equipment is operated in a system overload condition, the equipment is
 6 stressed, and useful life is reduced. Additionally, this impacts system operability
 7 by limiting jumpering abilities needed to support customer reliability during outage
 8 events. Without jumpering capabilities to adjacent circuits, outages will be
 9 sustained for longer periods of time because the failed equipment must be replaced

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1 to restore customers. Furthermore, overloaded equipment can also increase the
2 probability of emergent failures leading to customer outages.

3
4 Also, when there are overloads on the system it is challenging for the Company to
5 serve new customers and provide the ability for existing customers to expand,
6 therefore, in areas where system overloads exist, the absence of electrical capacity
7 inhibits DTE's ability to support economic growth in SE Michigan. This challenge
8 is also expected to increase with increasing loads brought by electrification and
9 distributed generation as part of the clean energy transition.

10

11 **Q87. How does The Company forecast and mitigate system overloads?**

12 A87. The Company conducts annual Area Load Analysis (ALA) on all distribution
13 circuits and substations to determine where there are overloads on the system.
14 Based on a study of historical ALA's, approximately one-third of distribution
15 substations have loading constraints. This includes substations operating over its
16 firm ratings and/or circuit equipment working near or over its day-to-day rating
17 during peak hours.

18

19 In areas that have seen and continue to see steady load growth, capital investments
20 are required to prevent overloads. These projects are categorized as System
21 Loading projects. The projects in the table below are proposed within the System
22 Loading category with additional details within Exhibit A-23 Schedule M6.

23

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Table 10 System Loading Projects

Project Name	Municipality	Drivers
Brest Substation	Monroe	Project is completed. Project Drivers were: Safety: Concrete and support structures at BREST substation required significant repair and oil breakers were at end of life. Operating safety & risk of prolonged customer outage. Capacity: secondary driver to increase capacity while decommissioning 4.8kV switchgear
Carleton Substation Upgrades	Ash Twp	Project is completed. Capacity: Carleton substation 196% of the maximum loadability. Transformer 2 is at 112% of its day to day rating. CARLT DC 312 is at 124% of its day to day rating and exceeds the 3MVA distribution design order limit for a 4.8kV circuit. Operability: Limited jumpering options due to substation and circuit loading. Failure can lead to customer outages/stranded load.
Grayling	Shelby Twp	Project is completed Capacity: Grayling substation is a heavily loaded 120-13.2kV substation providing service to the high growth commercial and industrial businesses along 23 Mile and 24 Mile in Shelby Township. All Grayling circuits are at capacity Reliability: Improve SAIDI by 50% Operability: Grayling substation is surrounded by overloaded substations
Prospect	Superior Twp	Capacity: Prospect Transformer 1 has exceeded the day-day rating at 119% in 2020 and substation at 119% of Firm Rating. As Engineering developed scope for this project, upgrades at Prospect have been cancelled as all load from Prospect substation will be served by the upgraded Grenada System Loading Project. Load from Prospect has temporarily been transferred to adjacent circuits to mitigate overload conditions.
Mandy 307 Load Transfer	Royal Oak	Reliability and Operability: Mandy DC307 is currently 126% of its firm rating. The day-to-day circuit rating is violated since 2016. The day-to-day rating for Mandy DC307 is 2.7 MVA and the peak for the circuit is 3.4 MVA. The circuit Mandy DC307 is surrounded by a dense tree area creating significant amount of outages.
Mack Transformer 102	Detroit	Project is completed. MACK TRF102 installation was completed to allow for the repair of inoperable LTCs on MACK TRF101 and MACK TRF104 without putting customers served out of MACK at risk for a long outage. Upon completion of the needed repairs TRF102 is to operate in standby to provide additional reliability. This would have put 101MVA (26,000 customers) at risk for a long outage if the other TRF were to fail during the shutdown.
Globe	Vassar Twp, Tuscola County, MI	Safety: 4.8kV causes a higher safety risk in the event of a wire-down. Capacity: GLOBE is at 2.4 MVA, or 75% of its DD rating. Vassar Township has been issuing permits for Indoor Agricultural Centers, resulting in high load demand, which cannot be supported by existing Globe infrastructure. Operability: No jumpering option available between Globe and nearby Sheridan substation. Other: GLOBE TRF size needs to be increased to provide load relief opportunities for future SHRDN substation. Active customer load addition requests in the area pending project completion.
Brown City	Brown City, Marlette and Imlay City	Safety: 4.8kV causes a higher safety risk in the event of a wire-down. Capacity: Substations over firm rating. Circuits approaching Day to Day rating Operability: BRCTY substation is a 4.8kV distribution substation and surrounded by TCOMA substation, which is a 13.2kV distribution substation. This limits jumpering options for BRCTY substation.
Port Sanilac	Sanilac county	Safety: Aging infrastructure has a risk of failure. 4.8kV causes a higher safety risk in an event of a wire-down. Reliability: Forester has an aged Line Section Breaker (LSB) in need of replacement. 3-333kVA pole mount transformers at Forester are also at-risk equipment at Forester substation. The circuits at Port Sanilac are limited by substation regulators that are considered at-risk with no spare parts available. Capacity: Substations over firm rating. Circuits over Day-day rating. Forester substation is a Class T substation with a single circuit. Operability: There is limited/no jumpering options during peak since Port Sanilac is surrounded by Forester and Applegate substations, both of which are approaching/exceeding their substation transformer limits. Failure can lead to customer outages/stranded load.
Richmond/Armada	Richmond and Armada	Safety: 4.8kV causes a higher safety risk in an event of a wire-down. Reliability: The 4.8kV switchgear at Richmond substation was installed in 1956 and is the only oil filled truck type outdoor switchgear remaining on the DTE system. The breakers along with the CTs have no spare parts available. Capacity: Substation over firm rating. Circuits over distribution design order. Operability: Armada has limited jumpering options so when the substation needs maintenance, a portable substation is required to pick up the load.

2

Line
No.

1

Table 10 System Loading Projects, Continued

Project Name	Municipality	Drivers
Cody	South Lyon / Lyon Township	Safety: There are large 4.8kV (ungrounded system) ISO-down pockets, which are a hazard to the public. Reliability: The last tree trim was in 2015 which explains the second largest outage factor of trees. Capacity: Substation over firm rating. Circuits exceed distribution design order. Additional load growth expected due to new development. Operability: Due to loading there are no jumpering options inside of sub and little no jumpering options outside of the sub in the case of a failure. Failure can lead to customer outages/stranded load.
Otsego/Capac/Shaw	Imlay Twp	Capacity: Substations over firm rating. Circuits exceed distribution design order limit. Operability: Substation throwover is blocked due to loading. Little to no outside jumpering available. Failure can lead to customer outages/stranded load. Other: Execution of the project is key in providing capacity on OTSGO substation to initiate a different project to move IMLAY load to OTSGO and allow for decommissioning of IMLAY.
Macomb Substation	Clinton Twp, Macomb County, MI	Safety: 4.8kV causes a higher safety risk in the event of a wire down. Capacity: Substations over firm rating. Circuits over Day to Day rating. Circuits exceed Distribution design order of 8MVA per 13.2kV circuit.
Grenada	Ann Arbor	Grenada substation is located in Ann Arbor. There are four substations serving the general area: Grenada, Price, Prospect and Wolverine. Safety: 4.8kv areas of Pospect: 4.8kV wire down elimination Reliability: GRENA has a 3-year average SAIDI of 1,487 Capacity: Substations over firm rating. Circuits over distribution design order. There is continued load growth in the area and the existing substations and circuits are unable to support Ann Arbor's electrification goals. Operability: There is a lack of jumpering capability for Grenada, Prospect and Price substations. The use of distributed generation would be required in the case of any failure at the substations mentioned above. Failure can lead to customer outages/stranded load.
Lark/Spruce	Ann Arbor	Safety: Spruce substation (SPRUC) has equipment that has been designated as high risk. It will be easier to replace this equipment once the substation expansion is completed at LARK (120-40kV ITC/DTE Station in proximity of Spruce). Reliability: Spruce circuits have frequent outages that have resulted in higher than system average SAIDI and CAIDI minutes. There are sections of circuits that are located in difficult to access areas which are problem areas for downed wires. Capacity: Spruce substation loading is over its firm rating. There are circuits that have exceeded the Distribution Design Order (DDO) limit for 13.2kV loading with other circuits approaching that limit in the near future. There is limited capacity for load growth in the area. Operability: Spruce circuits have areas that are 13.2kV islands (adjacent to 4.8kV) which has led to limited jumpering points and little opportunity for load transfers.
Jewell	Washington Twp	Reliability: The largest causes of outages is due to trees and equipment break. The circuits have been close to and have gone over the DTE average for SAIDI/CAIDI. Capacity: Substation over firm rating. Multiple circuits over and approaching day to day rating. Multiple circuits exceed distribution design order. There is load growth and new business across the Jewell Substation area. Operability: little to no load transfers available. Failure can lead to customer outages/stranded load. Other: There has been several residential developments happening on JEWEL within the past couple years. JEWEL area has a lot of open land so we can expect for more businesses and residential developments to come.
Mayville	Mayville, Clifford	Safety: 4.8kV causes a higher safety risk in the event of a wire down. Reliability: The area has suffered from extensive outage events that lead to a large amount of stranded load for more than 24 hours. Capacity: Substations over firm rating. Circuit over day to day rating. Circuits over distribution design order limit.
Goodison	Oakland Twp	Reliability: GODSN SAIDI and SAIFI usually is above the DTE system average. Issues from TIE line cause outages to the substation, especially in 2023. Capacity: GODSN is at 129% of its firm rating. Both GODSN circuits exceed the Distribution Design Order limit of 8MVA for a 13.2kV circuit. Operability: Jumpering options outside of GODSN are not available during summer peak due to TINKN and JEWEL substations exceeding their firm ratings and because of the heavy loading on neighboring circuits. Overloads and low voltage occur when load is jumpered over to neighboring substation.

2

Line
No.

1

Table 10 System Loading Projects, Continued

Project Name	Municipality	Drivers
Wixom	Wixom	Safety: Existing PDC and TRF1 are in close proximity, which is a fire hazard and is a worker safety hazard. In addition to the loading concerns at the substation, the existing switchgear at the substation is reaching its end of life and the breakers are at an elevated risk due to interruption medium. Reliability: SAIDI fluctuates year after year for WIXOM circuits and a few circuits exceed DTE system average. Most outages occur during storm. Capacity: Substation over firm rating. Circuits over distribution design order. Circuits above nominal cable day to day ratings. Operability: When a substation transformer fails, then at least (2) diesel generators are needed to support load at summer peak. There are only (2) jumpering points outside of Wixom substation at summer peak. Other: Receiving multiple method of services (customer load requests). WIXOM cannot support industrial customers due to existing circuit loadings. Wixom is the fastest growing city in Michigan.
Diamond	Dexter	Diamond substation is a two transformer, four circuit substation and is at 137% of its firm rating. Reliability: In summer 2018, load shedding was implemented at the substation due to equipment overloads. SAIFI 5 year average is 1.97 and SAIDI 5 year average is 566. Capacity: Two of the four circuits exceed the distribution design order standard of 8MVA for a 13.2kV circuit. The substation is currently at 137% of firm rating. Operability: Transformer #1 was replaced during an emergency failure event in March 2019; firm rating is now limited by smaller sized transformer #2.
Spokane/Seneca	Rochester Hills	Safety: Substation flooding due to the lack of a drainage system at Spokane substation has damaged the conduit system by causing it to cave in. This has impeded the use of the 9-position switchgear and the associated third transformer at the site. Capacity: Substations over firm rating. Circuits exceed distribution design orders of 8MVA per circuit. Operability: Limited jumpering options outside of Spokane substation due to overloads at adjacent Seneca and Tienken substations. Failure can lead to customer outages/stranded load. Other: DTE's Equipment Performance and Protective Maintenance group recommends the replacement of the current 11-position switchgear, as it is at risk of failure.
Sterling	Sterling Heights, Macomb County	Capacity: Circuit approaching day to day limit. Circuits exceed distribution design order limit. There is evidence of re-development and steady growth still coming into the Substation area. Load cannot be transferred to adjacent circuits without causing similar loading issues. There are no positions available at Sterling Substation to create new circuits to provide relief and additional capacity. Other: The current switchgear at Sterling substation is not the standard DTE setup. It is a straight bus switchgear which is exposed to a single point of failure.
Disco	Sterling Heights	Safety: There is a high chance of wire downs in the area due to DISCO OH lines being surrounded by many trees. The main cause of wire downs in the area are caused by winds and trees. A portion of DISCO OH lines are also truck inaccessible. Reliability: DISCO circuits currently have limited jumpering options due to the neighboring circuits being over loaded. In 2022 the SAIDI and CAIDI for all DISCO circuits were above the DTE system average due to several day outages. Trees and wind were the main causes for the outages. Capacity: Substation over firm rating. Circuits over distribution design order. Operability: DISCO circuits have limited jumpering options due to neighboring circuits being overloaded. Failure can lead to customer outages/stranded load.
Tahoe	Novi	Capacity: Tahoe substation is over its firm rating. Since Novi Substation is being decommissioned and the load is being transferred to Tahoe, peak loads at TAHOE DC 8928 and TAHOE DC 9512 will exceed the distribution design order standard of 8.0 MVA for a 13.2kV circuit. TAHOE DC 9511 is also approaching the Distribution Design Order limit. Operability: Current loading conditions inhibit the creation of jumpering points and installation of loop schemes in the area.

Line
No.

1

Table 10 System Loading Projects, Continued

2

Project Name	Municipality	Drivers
New Baltimore / Chesterfield	Chesterfield/ New Baltimore	Safety: 4.8kV causes a higher safety risk in the event of a wiredown. Reliability: NBALT is over its blocking limit to protect TRK4911 and a loss of transformer 3 will result in 3MVA of stranded load. Capacity: Substations over firm rating. Circuits over day to day rating. Circuits over distribution design order limit. Operability: Limited jumpering options available. Failure can lead to customer outages/stranded load. Other: There have been three Method of Service requests since January 2021 totaling 2.3MVA load increase at NBALT substation. There have been 6 Method of Service requests since January 2021 bring 2.24MVA of load to CHEST substation.
Kings Point	Clinton Township and Mount Clemens, Macomb Twp	Safety: 4.8kV causes a higher safety risk in the event of a wiredown. Capacity: Substation over firm rating. Circuits over day to day rating. Circuits over distribution design order. Nearby Omega substation is a 40kV-13.2kV substation which is 5.4MVA of its blocking limit. The loss of either transformer at Omega substation results in 5.8MA of stranded load. The subtransmission lines are overloaded in the area (Trunk 7909 and Trunk 6759). The current infrastructure is unable to support new load growth in the area. Operability: Omega and surrounding substations high loading limits jumpering options. Failure can lead to customer outages/stranded load.

3

Q88. What are the benefits of System Loading projects?

A88. System Loading projects alleviate the stress on the system caused by overloads and reduce potential failures. These projects increase capacity and reconfigure the system to eliminate projected overloads on specific pieces of equipment (overhead wire, underground cable, transformers), or at the circuit/substation level. While each project may add a different amount of new capacity, following completion of a system loading project, substations shall be under 100% of firm rating, and all equipment shall be under 100% of day-day rating. Capital investment to address these system overloads will also improve reliability and provide capacity for new and existing customers. Additionally, system loading projects help maintain/improve system operability by restoring/creating jumpering capabilities and removing aged equipment from the system.

16

Line
No.

1 The best way to demonstrate the benefits of System Loading projects is to use an
2 example. The Grenada project will deliver on system loading, conversions, and
3 automation benefits. The first step of the project is to rebuild and convert a portion
4 of an adjacent Prospect circuit which will deliver improved reliability from the
5 rebuilds, but also mitigate an overload at Prospect substation which is currently
6 over 100% of firm rating. Construction of a new Grenada substation will increase
7 capacity by 77% versus the existing Grenada substation, providing capacity for
8 continued growth and mitigating circuit overloads. Finally, additional conversions
9 will enable installation of loop schemes and circuit automation; none of which are
10 possible without the capacity delivered in the system loading project. When fully
11 implemented, the project is anticipated to deliver an 88% improvement in reliability
12 versus three-year historic SAIDI for the area.

13

14 Even though each of the projects in the System Loading program are designed to
15 address the concerns/issues for a particular part of the grid, they have similar
16 benefits in the range of what was discussed for Grenada.

17

18 **Q89. What is the scope of work for System Loading projects?**

19 A89. System Loading projects include scope to add capacity to the distribution system,
20 and typically include:

- 21 • Acquisition of land for new substations, if necessary
- 22 • Construction of new substations
- 23 • Expansion of current substations by installing additional transformers
- 24 • Replacing existing transformers
- 25 • Installing new switchgear lineups

Line
No.

- 1 • Creating new distribution circuits
- 2 • Reconductoring circuits (overhead wire and/or underground cable)
- 3 • Converting circuits to higher voltage, where necessary and transferring
- 4 load once additional capacity has been created

5 Many areas identified in the priority ranking for system load relief are addressed as
6 part of CODI, 4.8 kV Conversion, or 8.3 kV Pontiac Conversion programs. Load
7 relief needs excluded from conversion programs are included in the System
8 Loading projects category.

9

10 **Q90. How are system loading projects prioritized?**

11 A90. Distribution engineers assess the load on the system and its impact on individual
12 pieces of equipment under two conditions: normal state and contingency state. This
13 analysis determines if adequate distribution system capacity exists to serve both
14 current and projected future demands.

15

16 System loading information from this analysis is updated and evaluated annually.
17 Projects are evaluated for load relief on how they address five factors: substation
18 equipment overload, substation over firm rating, circuit equipment overload, strong
19 load growth or circuits over 8 MVA for 13.2 kV circuits and 3 MVA for 4.8 kV.
20 Based on these variables a priority ranking of the load relief projects is developed.
21 More information about Load Relief criteria and prioritization can be found in
22 Section 9.1 of the DGP (Exhibit A-23 Schedule M8 sponsored by Witness
23 Kryscynski).

Line
No.

1 **Q91. Can you summarize the key themes of your testimony?**

2 A91. Yes. Projects in Infrastructure Redesign and Modernization pillar are a key part of
3 the Company's plan for the grid of the future and fundamentally change the way
4 the grid operates. These projects add capacity by converting the distribution system
5 to a higher voltage for growing customer load, reduce outages and shorten outage
6 restoration time by incorporating modern technology and equipment, hardening the
7 grid, improve redundancy and resiliency of the system, and increase safety. IRM
8 treatment of these types of investments can benefit customers by ensuring that
9 projects are deployed where they are needed most.

10

11 The projects in this pillar are vital to support the continued resurgence of the city
12 of Detroit and to provide the needed energy to ensure a bright future for Michigan.

13

14 **Q92. Does this complete your direct testimony?**

15 A92. 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

| REVISED REBUTTAL TESTIMONY

OF

SATVIR S. DEOL

DTE ELECTRIC COMPANY
REVISED REBUTTAL TESTIMONY OF SATVIR S. DEOL

Line
No.

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

3 A1. My name is Satvir S. Deol (he/him/his), and my business address is One Energy
 4 Plaza, Detroit, Michigan, 48226 and I am employed by DTE Electric Company
 5 (DTE Electric or 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 and recommendations for
 14 disallowances of capital projects as proposed by certain witnesses that provided
 15 direct testimony in the instant case. These witnesses include:

- 16 • Michigan Attorney General (AG), Michigan Environmental Council
- 17 (MEC), Natural Resources Defense Council (NRDC), collectively referred
- 18 to as “AG-MN” Witness Stephens
- 19 • Ann Arbor Witness Stults
- 20 • Detroit Area Advocacy Organizations (DAAO) Witness Koeppel
- 21 • Michigan Attorney General (AG), Michigan Environmental Council
- 22 (MEC), Natural Resources Defense Council (NRDC), Sierra Club (SC), and
- 23 Citizens Utility Board of Michigan (CUB), collectively referred to as
- 24 “MNSC” Witness Woolley

Line
No.

- 1 • Association of Businesses Advocating Tariff Equity (ABATE) Witness
2 York

3 The absence of a discussion of other matters in my rebuttal testimony should not
4 be taken as an indication of agreement with other aspects of any intervenor's
5 testimony.

6

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

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

9	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
10	A-50	OO1	Discovery Response MNSCDE-5.5a(S1)
11	A-50	OO2	NDA CEII MNSCDE-5.5a(S1) –
12			Subtransmission Load Data
13	A-50	OO3	Discovery Response MNSCDE-8.5a

14

15 **Q5. Were these exhibits prepared by you or under your direction?**

16 A5. Yes, they were.

17

18 **Q6. How is your testimony organized?**

19 A6. There are eight specific topics I will rebut in my testimony, as listed below. A
20 detailed discussion of why the intervenor's recommendations should not be
21 accepted by the Commission follows.

22

Line
No.

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31		
32		

Line
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1 **Part I: Conversions**

2

3 **Q7. Which intervenors offer testimony regarding circuit conversions that you wish**
4 **to rebut?**

5 A7. AG-MN Witness Stephens challenges the overall justification for conversion
6 projects. DAAO Witness Koeppel offers testimony claiming there is conflict
7 between my direct testimony and that of Company Witness Kryscynski regarding
8 City of Detroit Infrastructure (CODI) conversions. I address Witness Stephens and
9 Witness Koeppel in Rebuttal Topic 1 and Rebuttal Topic 2, respectively.

10

11 **Rebuttal Topic 1: AG-MN Witness Stephens' claims regarding the Company's**
12 **conversion programs**

13 **Q8. What does Witness Stephens recommend with respect to the Company's**
14 **circuit conversions program?**

15 A8. Witness Stephens does not recommend any specific disallowance of the Company's
16 capital expenditures in the instant case, however he does recommend that the
17 Commission reject the Company's proposal to include conversions in the 2026 and
18 2027 IRM¹. Company Witness Foley's rebuttal testimony, page 21, line 18 through
19 page 24, line 23, in the instant case addresses the 2026 and 2027 IRM.

20

21 Related to his analysis of the Company's circuit conversions program, Witness
22 Stephens also makes other recommendations and statements as summarized below
23 that I will cover in my rebuttal:

¹ Stephens DT, p. 23, lines 13-14

Line
No.

- 1 • Witness Stephens recommends that the Company support the pace at which
- 2 it plans to convert its 4.8 kV. He additionally states that the Company's
- 3 justification of reliability, safety, and capacity does not support the 15-year
- 4 goal stated in the DGP². Witness Stephens also states that the Commission
- 5 should direct the Company to solicit an independent expert to assess the
- 6 appropriate rate of conversions³.
- 7 • Witness Stephens states that the Company lacks transparency in the
- 8 information provided regarding its capital expenditures⁴.
- 9 • Witness Stephens recommends that the Commission require the Company
- 10 to establish and present metrics, such as dollars per circuit mile converted
- 11 in future rate cases⁵.
- 12
- 13 Other statements and recommendations in Witness Stephens' assessment of the
- 14 Company's circuit conversions program that are addressed more generally in other
- 15 Company witness's rebuttal testimonies are as follows:
- 16 • Witness Stephens states the Company must provide an independent analysis
- 17 showing its EV adoption forecasts are likely, that its assumptions about EV
- 18 charging behavior are accurate, and that these forecasts and assumptions are
- 19 associated with geographies, substations, and circuits⁶. Company Witness
- 20 Bennett's rebuttal testimony, Topic 6 [EV Forecast], in the instant case
- 21 addresses these recommendations.

² Stephens DT, pp. 18 - 20

³ Stephens DT, p. 23, lines 14-16

⁴ Stephens DT, pp. 20 - 23

⁵ Stephens DT, p. 24, lines 1 – 3

⁶ Stephens DT, p. 23, lines 16 – 20

Line
No.

1 • As part of his assessment of the Company’s pace of circuit conversions,
2 Witness Stephens states the Company has not provided a benefit-cost
3 analysis (BCA)⁷. He also argues that the Company’s investments in circuit
4 conversions, along with other initiatives, are “discretionary” work that has
5 not been adequately supported⁸. Company Witness Kryscynski’s rebuttal
6 testimony in the instant case addresses these claims in Rebuttal Issue 2
7 [“Discretionary”] and Rebuttal Issue 5 [BCA].

8

9 **Q9. What does Witness Stephens believe regarding the pace and 15-year**
10 **timeframe at which the Company plans to convert its 4.8 kV circuits?**

11 A9. Witness Stephens argues that “as DTE likely built these circuits over a 50-year
12 period from 1900 to 1950, rebuilding all these circuits in 15 years is an
13 unreasonable aspiration⁹.”

14

15 **Q10. Is Witness Stephens’ reference to the initial building of the 4.8kV grid in**
16 **southeast Michigan relevant to the current customer needs driving the timing**
17 **of the Company’s conversion program?**

18 A10. No. Different customer drivers determined timing of the initial grid build such as
19 population growth in the early Michigan population centers and the eventual
20 development of rural areas. In contrast, the Company’s current conversion
21 investments are being driven by increasing electric capacity needs, system
22 performance caused by aging infrastructure, and potential public safety hazards of
23 an ungrounded 4.8kV delta system.

⁷ Stephens DT, p. 18, lines 2 – 3

⁸ Stephens DT, p. 45

⁹ Stephens DT, pp. 17 – 18

Line
No.

1 **Q11. Why has the Company developed a goal of converting its remaining aged**
2 **4.8kV circuits in 15 years?**

3 A11. The 15-year conversion goal is a directional target and may change in timing and
4 priority as specific grid needs evolve in different geographic areas and circuits. In
5 Case No. U-20147 the Commission requested that the Company provide a long
6 term (15 year) vision of the grid stating:

7

8 “Therefore, the Commission directs DTE electric, Consumers, and I&M to
9 continue to develop detailed distribution plans over a five-year period, but also
10 include in the plan their vision and high-level investment strategies 10 and 15 years
11 out.¹⁰”

12

13 This 15-year conversion directional goal was developed as part of the Company’s
14 long-term vision for the grid. However, the customer needs of a safer, more reliable,
15 and resilient grid, with more capacity to support electrification are important now,
16 and not expected to diminish over time. Ultimately, the grid will be rebuilt at a pace
17 required to support customer needs and affordability. The conversion investments
18 in this case are supported by near-term drivers highlighted in my testimony, such
19 as capacity needs, reliability improvements, and addressing aging and end of life
20 infrastructure.

21

22 **Q12. What does Witness Stephens claim regarding the customer reliability as it**
23 **relates to conversion of aged 4.8kV circuits?**

¹⁰ MPSC Order in Case No. U-20147 dated September 11, 2019, p. 4

Line
No.

1 A12. Witness Stephens claims “[r]eliability improvement is not a reasonable justification
2 because data the Company provided in discovery in U-21297 shows the reliability
3 of 13.2kV circuits (as measured by system average interruption duration without
4 major event days) was worse during 2018- 2022 (124 minutes) than the reliability
5 of 4.8kV circuits over the same time period (97 minutes)¹¹.”

6

7 **Q13. Do you agree with Witness Stephens’ claim regarding the lack of customer**
8 **reliability improvements that occur with circuit conversions?**

9 A13. I do not agree with Witness Stephens’ conclusion for the following reasons. First,
10 while the estimated reliability benefits vary with the specific data for each circuit
11 and project, for the conversions that are included in the instant case, the average
12 projected reliability improvement is estimated to be up to 90% as stated on page 14
13 of my direct testimony.

14

15 Secondly, Witness Stephens arrived at the incorrect assertion that 13.2kV circuits
16 had poorer reliability performance than 4.8kV circuits by examining the more
17 narrowly defined SAIDI ex-MED. In reality, for the same period of time, customers
18 served from 13.2kV circuits experienced 17% better performance than those served
19 from 4.8kV circuits when one takes in to account the all-weather SAIDI, as shown
20 in Table 1 below.

21

22

Table 1 All Weather SAIDI Average 2018 – 2022

Circuit Voltage	4.8kV	13.2kV
SAIDI Minutes	623.2	514.8

¹¹ Stephens DT, p. 18, lines 14 – 19

Line
No.

1 Finally, a simple comparison of 4.8kV versus the existing 13.2kV system is not
2 indicative of the reliability improvement benefits expected from current 4.8kV
3 conversion projects. The 13.2kV circuits that were built decades ago are not
4 constructed to the same standards and specifications as the more resilient 13.2kV
5 circuits the Company constructs today. The updated Grade B construction standard
6 used in the current conversion projects includes more reliable insulators with
7 polymer material that provide greater leakage current protection compared to the
8 existing porcelain insulators, fiberglass crossarms instead of wood (or armless)
9 with greater mechanical and structural loading strength, larger and stronger wood
10 or in some cases steel or concrete poles for truck-accessible circuit backbone and
11 highway crossings, and larger, higher-strength wires which all factor into
12 improving resiliency in the face of storms and overall reliability performance.
13 Furthermore, conversions provide added benefits of greater load carrying capacity,
14 increased connection points between adjacent 13.2kv circuits, and circuit
15 automation with loop-schemes will provide dramatic improvements in reliability
16 and resiliency performance with much quicker restoration of service during outage.
17

18 **Q14. Does witness Stephens agree with the Company that improved safety supports**
19 **the need to convert the aged 4.8kV system with conversions?**

20 A14. No. Witness Stephens states, “as described in the DTE’s 4.8kV Hardening
21 program, the design of the Company’s 4.8kV circuits likely increases the risk that
22 a downed conductor will remain energized if it falls to the ground¹².” In this
23 statement Witness Stephens indicates that he understands the public safety risk
24 associated with a downed conductor of a 4.8 kV ungrounded delta system. He then

¹² Stephens DT, p. 19, lines 2 – 4

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1 goes on to state, “however, this is a design condition that has existed on the
2 Company’s 4.8kV circuit since they were constructed, likely between 75 and 120
3 years ago¹³.” Despite acknowledging the associated safety hazards to customers
4 and company employees of the ungrounded 4.8 kV delta system, Witness Stephens
5 then dismisses this safety hazard solely because these 4.8kV circuits have been in
6 place for a long time.

7

8 **Q15. Does the Company agree with Witness Stephens’ assessment of safety of the**
9 **aged 4.8 kV ungrounded delta system?**

10 A15. No. The Company disagrees with Witness Stephens’ assessment and believes that
11 reducing the risk associated from potential energized downed wires of the 4.8 kV
12 ungrounded delta circuits should be a major focus and a justification for converting
13 the 4.8 kV circuits. The Company does not believe that the circuit design existing
14 for 75 to 125 years is a reasonable justification for slowing down its pace of
15 conversions.

16

17 **Q16. What does Witness Stephens state about the benefits of capacity in circuit**
18 **conversions?**

19 A16. Witness Stephens states that “circuits with peak loads above or near equipment
20 ratings should be prioritized for conversion first¹⁴.” Witness Stephens also alludes
21 that the Company only has a small percentage of 4.8kV circuits that exceed day-to-
22 day rating (5.7%) and that this is not a sufficient justification for the pace of
23 conversions¹⁵. He goes on to state that the Company should synch the focus of

¹³ Stephens DT, p. 19, lines 4 – 6

¹⁴ Stephens DT, p. 19, lines 10 – 11

¹⁵ Stephens DT, p. 19, lines 9 – 10

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1 near-term conversions to those areas where 4.8kV substations are over firm, where
2 there are circuit overloads, and where there are increased requests for electric
3 service either via new business or electrification¹⁶.

4

5 **Q17. Does the Company agree with Witness Stephens' assessment of the Company's**
6 **justification for converting 4.8kV circuits based on circuit loading?**

7 A17. In part. The Company agrees that conversions should be prioritized based on
8 loading, however, this is only one of several factors to consider when prioritizing
9 circuit conversions. Other factors, as included in my direct testimony, are safety
10 and reliability. The Company disagrees with Witness Stephens' assessment that is
11 based on day-to-day loading data for one year, 2022. One must examine circuit
12 loading trends over time, as well as the other metrics of peak capacity, and the
13 number of substations/circuits that are over their firm rating. Additionally, the
14 Company must maintain a capacity margin for operating the system during
15 maintenance and trouble events. This includes not just day-to-day circuit capacity,
16 but also the source substation capacity¹⁷, and circuit emergency ratings, which all
17 impact the ability to operate the system during planned or unplanned outage events
18 as well as the ability to support load growth. As stated in the Company's 2023 DGP
19 filing, the Company prioritizes near-term conversions from a capacity standpoint
20 in those areas where 4.8kV substations are over firm, where there are circuit
21 overloads¹⁸. The Company also takes into account areas where there are increased
22 requests for electric service either via new business or electrification.

¹⁶ Stephens DT, pp. 19 – 20

¹⁷ 20% of the Company's 4.8kV substations operate over firm rating.

¹⁸ 2023 DGP, Ex A-23, Sch. M8, pp. 119-121

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1 **Q18. What is your response to Witness Stephens' recommendation that the**
2 **Commission should direct the Company to solicit an independent review of its**
3 **planned rate of conversions?**

4 A18. Pursuant to the Commission's order in Case No. U-21305, a broader independent
5 third-party review of the Company's electric distribution system including system
6 performance and investment plans is already underway. The Company believes that
7 Witness Stephens' recommendation should be disregarded since an additional
8 third-party review will be redundant to the currently in progress audit and
9 premature.

10

11 **Q19. Does Witness Stephens make an apples-to-apples comparison across the**
12 **Company's documents provided in the instant case?**

13 A19. No, he does not. Witness Stephens uses the 4.8kV CC: Almont Relief Circuit
14 Conversion (Midas) project to demonstrate what he calls a lack of transparency in
15 the Company's conversion projects. In this example, he acknowledges that in the
16 instant case, the Company indicates a total project cost of \$30.7 million¹⁹. Witness
17 Stephens then compares this \$30.7 million to a section of the capital appropriation
18 request form (CARF) showing \$36.2 million²⁰.

19

20 The section of the CARF that includes this \$36.2 million is indicated by the red box
21 in Figure 1 below and is intended for internal Company review. The correct figure
22 in the CARF to compare against is the \$30.3 million project approval indicated by
23 the green box in Figure 1 below. It should also be noted that per the
24 recommendations made by ALJ in Case No. U-21297, the Company is now

¹⁹ Stephens DT, p. 21

²⁰ Stephens DT, p. 22, lines 5 – 6.

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1 including the total projected cost of its projects in the instant case²¹. This is set forth
2 in Exhibit A-23, Schedule M6 in the instant case where each project discussed
3 includes an estimated total project cost along with the annual forecast schedule
4 through the bridge and projected test periods. This is where Witness Stephens
5 identified the \$30.7 million total projected cost for the Midas project as shown in
6 Figure 2 below.

7

8 **Q20. Does the Company demonstrate transparency across the documents provided**
9 **in the instant case?**

10 A20. Yes, it does. The Midas project example that Witness Stephens uses in his direct
11 testimony demonstrates there is transparency across the documents presented by
12 the Company in the instant case. Witness Stephens seems to misunderstand the
13 information presented on (1) the CARF shown in Figure 1 below, (2) page 10 of
14 Exhibit A-23, Schedule M6, and (3) page 15, line 41 of Exhibit A-12, Schedule
15 B5.4.

16

17 As shown in Figures 1 and 2 below, the Company approved \$30.3 million for the
18 Midas project in the 2021 CARF and has identified an updated project forecast in
19 the instant case of \$30.7 million (Sch. M6). In Exhibit A-12, Schedule B5.4, page
20 15, line 41, the line item for the Midas project, the Company has identified 2022
21 actual spend of \$13.1 million and forecasted annual spend of \$3.9 million in 2023,
22 \$6.0 million in 2024, and \$1.0 million in 2025, or a total of \$24.1 million in the
23 instant case period. In Case No. U-21297, the Company identified \$5.6 million of
24 actual 2021 spend²² and in Case No. U-20836, the Company identified \$0.5 million

²¹ MPSC Order in Case No. U-21297, dated December 1, 2023, p. 84

²² MPSC Case No. U-21297, Ex. A-12, Sch. B5.4, p. 10, line 57

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1 of actual spend in 2020²³. It is evident that the Company has not provided annual
 2 spending “for only about \$11 million of this project” as Witness Stephens claims²⁴.

3

4

Figure 1 : 4.8kV CC Almont Relief and Circuit Conversion (Midas)

5

CARF

DTE Energy

Appropriation Request Summary Sheet

Project Name:	Midas Subs - Below grade, Conduit Midas Subs - Above grade, OH, Cable	Capital Budget / Project #:	I-000404-0027 (MEP) I-000801-0001 (DO)
Utility/Non-Utility:	Utility	Project Type:	Distribution
Business Segment:	Electric Utility	Business unit within budget?:	Yes
Business Unit:	MEP / DO	Project Start Date:	Mar-2019
Project Sponsor:	Joi Harris / Sharon Pfeuffer	In-Service Date:	2022, 2023
		Post Investment Evaluation Date:	2025
Current Approval Request (\$Millions):	\$28.9		
Previous Request(s) (\$Millions):	\$1.4		
Total Project (\$Millions):	\$30.3		

Financial Summary (\$Millions)

	2020 & Prior Years	2021	2022	2023	2024	2025	Beyond	Total
Current Capital Approval Request	\$0.0	\$21.3	\$6.3	\$1.3	\$0.0	\$0.0	\$0.0	\$28.9
Previous Request(s)	0.8	0.6	0.0	0.0	0.0	0.0	0.0	1.4
Total Project Request	0.8	21.9	6.3	1.3	0.0	0.0	0.0	30.3
Operating After-Tax Cash Flow	(679)	(17,017)	(10,235)	2,811	2,828	2,723	50,892	31,323
Net Income	17	310	1,185	1,448	1,395	1,340	19,921	25,616

Hurdle Rate	IRR	NPV	Payback(years)	First 5 Yrs Avg. Net Income	Customer cost (savings)*
6.1%	6.1%	\$264	15	\$ 871	\$36,182

Project Description and Approval

The purpose of this request is to obtain full appropriation for the Midas project.

MEP Project Scope:

- Design a new 120kV to 13.2kV Class RR substation (Midas) in Almont Township
- Construct all below grade elements of the new Midas substation
- Create Class R standards as part of the substation design
- Design and install all new system conduit to facilitate the OH circuit work starting outside of substation property

DO Project Scope:

Construct the above grade elements of the new Midas Class RR substation including testing and commissioning. Substation includes two (2) 15/20/25 120 - 13.2 kV transformers and four (4) line positions, Class RR. The future Midas substation will have provisions for expansion to a Class A substation with installation of a future (12) position PDC. Also included is the transfer and partial conversion of two (2) existing Almont 4.8 kV distribution circuits to four (4) future Midas circuits with both 13.2 and 4.8 kV service. After transfer of the Almont circuits to Midas, the existing Almont substation will be de-commissioned.

6

²³ MPSC Case No. U-20836, Ex. A-12, Sch. B5.4, p. 10, line 56

²⁴ Stephens DT, p. 21, lines 15 – 16

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Figure 2 : Midas Capital Project Detail from Ex. A-23, Sch. M6

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail – Infrastructure Redesign and Modernization

Case No: U-21534
Exhibit: A-23
Schedule: M6
Witness: S. S. Deol
Page: 10 of 404

(a)	(b)																				
Program:	4.8 kV CC: Almont Relief and Circuit Conversion (Midas)																				
Approximate Construction Schedule:	Substation Construction: 2021- 2024 Substation In Service: 2024 DC8298 Commission: 2024 DC8269 Commission: 2024 DC8715 Commission: 2024 DC8704 Commission: 2024 Decommission Almont Substation: 2025																				
Budget Basis:	Project Management Estimate																				
Total Cost: \1	The estimated project cost for this investment is \$ 30,730,922																				
Rate Case Projection:	<table><tr><td></td><td>12mo. 01/01/23 thru 12/31/23</td><td>12mo. 01/01/24 thru 12/31/24</td><td>12mo. 01/01/25 thru 12/31/25</td></tr><tr><td>Total Labor (DTEE & Contractors)</td><td>\$3,308,607</td><td>\$5,095,409</td><td>\$734,777</td></tr><tr><td>Material</td><td>\$635,595</td><td>\$904,591</td><td>\$265,223</td></tr><tr><td>Other</td><td>\$ 0</td><td>\$ 0</td><td>\$ 0</td></tr><tr><td>Total</td><td>\$3,944,203</td><td>\$6,000,000</td><td>\$1,000,000</td></tr></table>		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25	Total Labor (DTEE & Contractors)	\$3,308,607	\$5,095,409	\$734,777	Material	\$635,595	\$904,591	\$265,223	Other	\$ 0	\$ 0	\$ 0	Total	\$3,944,203	\$6,000,000	\$1,000,000
	12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25																		
Total Labor (DTEE & Contractors)	\$3,308,607	\$5,095,409	\$734,777																		
Material	\$635,595	\$904,591	\$265,223																		
Other	\$ 0	\$ 0	\$ 0																		
Total	\$3,944,203	\$6,000,000	\$1,000,000																		

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

2

3 **Q21. What is your response to Witness Stephens’ recommendation that the**
4 **Commission require the Company to “establish and present in its next rate**
5 **case metrics, such as dollars per circuit mile converted, to budget and monitor**
6 **circuit conversion costs²⁵?”**

7 A21. The Company disagrees with this recommendation. Conversion projects are
8 complex, and each project is unique and includes a number of factors including, but
9 not limited to, customer density, circuit pole density, substation layout design,
10 access limitations, etc. The Company believes that the variations inherent in
11 projects with very different scopes make a proposed “one-size-fits-all” metric such
12 as standard cost per mile converted of limited value.

²⁵ Stephens DT, p. 24, lines 1 – 3

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1 **Rebuttal Topic 2: DAAO Witness Koeppel’s characterization of the City of**
2 **Detroit Infrastructure (CODI) program**

3 **Q22. What does Witness Koeppel recommend with respect to the Company’s CODI**
4 **program?**

5 A22. Witness Koeppel recommends that the Commission reject or substantially reduce
6 the Company’s capital expenditures on the CODI program²⁶. The Company’s
7 capital expenditures between the historical test year, bridge period, and test year
8 are \$49.8 million, \$198.2 million, and \$48.4 million respectively, or \$296.4 million
9 total²⁷.

10

11 Witness Koeppel also recommends that the Commission require the Company “to
12 analyze changes in demographics over time when assessing the equity impacts or
13 its proposed investments” and that “the Commission should require the use of
14 regression analysis to have a complete understanding of equity outcomes along
15 lines of race and class²⁸.”

16

17 **Q23. What does Witness Koeppel claim with respect to the Company’s proposed**
18 **CODI investments in the instant case for which he recommends disallowance?**

19 A23. Witness Koeppel claims that the Company’s equity analysis of its infrastructure
20 redesign and rebuild projects is flawed and contradicts the support for the CODI
21 projects discussed in my direct testimony. Company Witness Kryscynski’s rebuttal
22 testimony in the instant case, Rebuttal Issue 11, addresses Witness Koeppel’s
23 misinterpretation of the Company’s equity analysis.

²⁶ Koeppel DT, p. 47, lines 4 – 6

²⁷ Summation of all CODI projects in Ex. A-12, Sch. B5.4, pp. 14 & 16, lines 28 – 36 and 79 – 82

²⁸ Koeppel DT, p. 47, lines 6 – 9

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2 **Q24. Has Witness Koeppel mischaracterized information presented in the instant**
3 **case by the Company regarding the CODI program?**

4 A24. Yes, he has. Witness Koeppel attempts to draw correlations between population
5 density and electrical system reliability performance. The CODI footprint is
6 outlined by him to show that it has better reliability performance (SAIDI) than
7 surrounding areas presumably because the population density is higher. However,
8 the SAIDI performance relative to surrounding areas is better because it is a
9 predominantly all-UG area in a dense urban environment, whereas the surrounding
10 areas outside of CODI are fed by overhead circuits. In fact, the CODI boundary
11 Witness Koeppel draws over the system in “Figure 2: CODI Program Outline from
12 SAIDI (sic) Census Tract” shows significantly worse reliability in the outer edges
13 of the geographic area where some overhead does exist within the footprint²⁹.

14

15 **Q25. What is your response to Witness Koeppel’s claim that the Company’s**
16 **rationale for its proposed CODI expenditures contradicts its own equity**
17 **analysis?**

18 A25. The CODI projects were specifically developed as their own initiatives due to the
19 uniqueness of the systems within its footprint as explained on page 29 of my direct
20 testimony: “The CODI area is served primarily by an all-underground system with
21 manhole access located in busy city center streets. Its reliability is dependent upon
22 the ability to have redundant capacity available on all power lines to transfer load
23 in the event of cable failures or planned shutdowns on the distribution and
24 subtransmission systems.” The drivers for the CODI projects were not wholly

²⁹ Koeppel DT, p. 46, Figure 2

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1 driven by reliability improvement, but on the need to address capacity for load
2 growth, maintaining sufficient redundancy to ensure reliability as outlined above,
3 and addressing aging infrastructure. It is not appropriate to compare the project
4 drivers and reliability performance of an all-underground system with an overhead
5 system, as the two are drastically different in age, design, and the environment in
6 which they exist and are maintained.

7

8 **Q26. Should the Commission consider benefits not only to customers in the**
9 **immediate CODI area, but benefits to customers served by those facilities in**
10 **the Company's broader service territory?**

11 A26. Yes, it should. The customer base in the CODI area is not only the new high-profile
12 developments highlighted in my testimony, but also includes many important
13 customers critical to the health and well-being of the entire City of Detroit
14 populace. The CODI area includes multiple governmental, educational,
15 transportation, entertainment, and health and wellness institutions that benefit all
16 residents in Detroit and the larger Southeast Michigan Region. Aside from the
17 multiple City of Detroit municipal offices that are located downtown, Wayne State
18 University, The Detroit Medical Center, Henry Ford Hospital, Detroit Receiving
19 Hospital, McNamara Federal Building, Detroit Public Safety Headquarters,
20 Michigan Science Center, Charles H. Wright Museum of African American
21 History, The Detroit Institute of Arts, Wayne County Criminal Justice Complex,
22 Fox Theater, Detroit Opera House, Detroit Music Hall, Ford Field, Comerica Park,
23 are just a few of the other important customers located in the CODI footprint.
24 Investment in the electrical infrastructure in the CODI footprint will benefit all
25 citizens of the City of Detroit and the surrounding communities.

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1

2 **Q27. Is there a better comparison to be made about the need for project**
3 **improvements as it relates to the reliability of the CODI area?**

4 A27. Yes, there is. A more relevant comparison to be made would be to other cities with
5 urban all underground systems and the industry reliability performance. As noted
6 on page 33 of my direct testimony: “The downtown Detroit AC Network has
7 experienced customer outages 22 times since 2016 or an average of 2.75 outages
8 per year. This is concerning, as AC Network systems normally provide reliability
9 that exceeds radial systems.

10

11 Typically, a network customer can expect to be out of service once every 58 years
12 and experience 4% of the interruptions of a radial underground system (New York
13 Public Service Commission, 2009 as quoted in Smith & Moffat 2010)”. This data
14 puts into context how the aged network infrastructure in the CODI footprint is
15 already approaching the end-of-life bathtub curve with failure rates and reliability
16 that drastically underperforms similar systems in the industry. This drives home
17 the importance of an accelerated initiative to address the issue to rebuild and
18 maintain the integrity of the system prior to the exponential escalation of large-
19 scale failures. This trend is similar to the experiences of other utilities such as
20 Indianapolis Power & Light (IPL), Pepco, and Southern California Edison (SCE)
21 that have experienced catastrophic failures on their urban network system leading
22 to large scale and pro-longed outages and manhole events³⁰.

³⁰ Indianapolis Power & Light Report, available at
https://secure.in.gov/iurc/files/IPL_Downtown_Network_Audit_Report_-_Final_Report1.pdf, accessed
August 12, 2024

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1 The CODI projects address these concerns through conversions, while also
2 increasing capacity and decommissioning aging 4.8kV and 24 kV infrastructure.
3 With the higher 13.2kV distribution voltage class and direct ties to 120kV sources,
4 the system ultimately ends up with significantly less infrastructure to operate and
5 maintain going forward.

6

7 **Q28. What should the Commission find with respect to Witness Koeppel's**
8 **recommendation to disallow the Company's \$296.4 million in capital**
9 **expenditures for the City of Detroit Infrastructure conversion program?**

10 A28. The Commission should find that Witness Koeppel's claim that the Company's
11 investments to improve the City of Detroit Infrastructure do not offer benefits to
12 the residents of Detroit to be unjustified and based on a mischaracterization of
13 information presented by the Company in the instant case. Therefore, Witness
14 Koeppel's recommendation to disallow the CODI expenditures should be
15 disregarded.

16

Potomac Electric Power Company Report, available at
<https://edocket.dcpsec.org/apis/api/Filing/download?attachId=7765&guidFileName=894021a2-eb62-4668-bb48-0a90ea0f492a.pdf>, accessed August 12, 2024

Southern California Edison Long Beach AC Network Outage Report, available at
https://newsroom.edison.com/internal_redirect/cms.ipressroom.com.s3.amazonaws.com/166/files/201510/Report%20on%20the%20SCE%20Long%20Beach%20Outage.pdf, accessed August 12, 2024

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1 **Part II: Subtransmission Redesign & Rebuild (Subtransmission)**

2

3 **Rebuttal Topic 3: AG-MN Witness Stephens' claims regarding the Company's**

4 **Subtransmission Redesign & Rebuild program**

5 **Q29. What recommendations are made by Witness Stephens in the instant case**
6 **regarding Subtransmission Redesign and Rebuild projects?**

7 A29. Witness Stephens recommends disallowance on three subtransmission projects- Tie
8 4105 Phase 3, Tie 4105 Phase 4, and Trunk 3509 - totaling \$28.15 million³¹.
9 Additionally, he recommends that the Subtransmission Redesign and Rebuild
10 projects should not be included in the 2026 and 2027 IRM as proposed by the
11 Company³². Company Witness Foley's rebuttal testimony, page 21, line 18 through
12 page 24, line 23, in the instant case addresses the 2026 and 2027 IRM. In addition,
13 Witness Stephens challenges the overall justification of these projects, stating
14 concerns with the projects' effectiveness and the Company's cost benefit analysis.

15

16 **Q30. What did Witness Stephens claim with respect to the Company's**
17 **subtransmission projects?**

18 A30. Witness Stephens makes several claims that are addressed in my rebuttal testimony.
19 These claims are as follows:

- 20 • Witness Stephens claims that because subtransmission service interruptions
- 21 account for a small amount of the Company's total service interruptions, the
- 22 investments in subtransmission projects are not effective³³. He goes on to

³¹ Stephens DT, p. 37, lines 10 – 13

³² Stephens DT, p. 37, lines 14 – 17

³³ Stephens DT, p. 33, lines 10 – 14

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- 1 add that the subtransmission grid already includes system redundancy and
- 2 the Company's investments in subtransmission projects are not necessary³⁴
- 3 • Witness Stephens also claims that subtransmission projects that result in
- 4 larger conductor and the replacement of wood poles with steel poles only
- 5 marginally improves system resilience. He supports his claim by citing that
- 6 wind and ice were responsible for only 1.3% of subtransmission equipment
- 7 outages from 2019 to 2023³⁵.
- 8 • He also claims that the Company has not identified alternatives for some of
- 9 the proposed subtransmission projects to permit a "bang for the buck"
- 10 comparison³⁶.
- 11 • He claims that the three projects (Tie 4105 Phase 3, Tie 4105 Phase 4, and
- 12 Trunk 3905) for which he recommends disallowance have not been
- 13 previously reviewed and approved by the Commission³⁷.
- 14
- 15 Finally, Witness Stephens again makes the claim that the Company has not
- 16 supported its capital expenditures with benefit-cost analyses (BCA) on the
- 17 Subtransmission Redesign and Rebuild projects. Company Witness Kryscynski's
- 18 rebuttal testimony, Rebuttal Issues 5, 6, and 7, in the instant case discusses the
- 19 Company's approach to BCA, Global Prioritization Model (GPM), and the
- 20 reliability model.
- 21

³⁴ Stephens DT, p. 33, lines 14 – 16

³⁵ Stephens DT, p. 34, lines 10 – 14

³⁶ Stephens DT, p. 36, lines 16 – 19

³⁷ Stephens DT, p. 37, lines 8 – 13

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1 **Q31. Do you agree with Witness Stephens' claim that subtransmission projects are**
2 **not effective because subtransmission service interruptions account for a small**
3 **amount of the Company's total service interruptions?**

4 A31. No. First, Witness Stephens himself notes, "... because the redundancy built-in to
5 subtransmission design is so significant, and customer service interruptions so rare,
6 as to make service interruptions unhelpful in evaluating subtransmission grid
7 reliability³⁸." Secondly, while by design the higher voltage subtransmission system
8 leads to less frequent interruptions or outages than the distribution system, Witness
9 Stephens fails to take into account when an outage does occur, it also leads to a
10 significantly larger impact resulting in a large number of customers out of power,
11 often for an extended amount of time. As described below, it is critical to improve
12 the reliability of the aged subtransmission system to prevent future interruptions
13 with large cascading customer outages and prevent the required deployment of
14 large generators and other portable equipment while time-intensive repairs are
15 completed.

16

17 **Q32. Do you agree with Witness Stephens' assessment of the Subtransmission**
18 **Redesign and Rebuild program regarding redundancy?**

19 A32. No. As discussed on page 46 of my direct testimony, because of its critical role and
20 the greater impact to the downstream distribution system, the design of the
21 subtransmission system, by necessity, needs greater design margins and
22 redundancy to the lines feeding substations of the distribution system, which
23 directly feed customers.

24

³⁸ Stephens DT, p. 33, lines 6 – 8

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1 Redundancy is also required to provide operational flexibility by allowing
2 intentional interruptions (equipment shutdowns) to safely perform proactive
3 maintenance activities and equipment upgrades, without impacting customer
4 service. In several instances, intentional interruptions are limited to a short window
5 of time during a year due to an existing thermal and/or voltage planning criteria
6 violation. These constraints limit the company's ability to serve customers during
7 a single equipment failure and plan for intentional interruptions required for system
8 upgrades and routine maintenance.

9
10 However, Witness Stephens does not consider that the Company must still maintain
11 the subtransmission system to ensure this redundancy during normal and
12 emergency operations. As discussed on page 50 of my direct testimony, the
13 subtransmission system is aging beyond 80 years old in some areas. This coupled
14 with ever-increasing severe weather exposures and storm, as well as increased
15 loading in selected areas have led to loss of available contingency power flow paths,
16 thus reducing redundancy and exacerbates resiliency challenges.

17
18 Additionally, Witness Stephens states "DTE's subtransmission system has likely
19 been in its current condition (with a significant proportion of its circuits in violation
20 of planning criteria) for several decades³⁹." From this, it can be interpreted that
21 Witness Stephens does not believe that the subtransmission system concerns need
22 to be addressed in the near term, and the Company can continue to operate as-is
23 indefinitely without any significant consequences to its customers. The Company
24 disagrees with this assessment. The subtransmission planning criteria violations

³⁹ Stephens DT, p. 36, lines 2 – 4

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1 and reliability concerns need to be addressed now and cannot be pushed off into the
2 future. The fact that a subtransmission line is operating with a planning criteria
3 violation today does not mean that it will continue to operate reliably tomorrow. If
4 these concerns are not resolved, the subtransmission system will continue to lose
5 its ability to maintain the required redundancy for which it is designed to ensure
6 grid reliability.

7

8 Given that subtransmission outages can impact multiple substations that can result
9 in more than 10,000 customers impacted, redundancy in the Subtransmission
10 system is an industry best practice to allow for continued customer service during
11 a single contingency situation.

12

13 **Q33. Was the Subtransmission Redesign and Rebuild program developed to**
14 **address the degrading redundancy issues on the subtransmission system?**

15 A33. Yes. As discussed on page 53 of my direct testimony, the Subtransmission
16 Redesign and Rebuild program was developed to address the identified planning
17 criteria violations and reliability performance concerns on the subtransmission
18 system that are compromising system redundancy and reliability. Detailed analysis
19 of the subtransmission system has determined that approximately one-third of
20 subtransmission circuits violate the Company's established planning criteria.
21 These subtransmission planning criteria is based on engineering principles and
22 violations must be addressed in a timely manner to remediate continual degradation
23 that would lead to outages on the subtransmission system with significantly larger
24 customer impacts as compared to the distribution system.

25

Line
No.

1 **Q34. How did the Company determine that approximately one-third of its**
2 **subtransmission system has planning criteria violation and what is the overall**
3 **impact?**

4 A34. Through an annual process of updating loading information into industry-standard
5 software, Subtransmission Planning Engineers analyze the condition of the system
6 to determine any existing or potential equipment overloads based on the defined
7 planning criteria and redundancy requirements. Pages 47 through 48 of my direct
8 testimony and Exhibit A-23, Schedule M8 DGP pages 101 - 102 detail this analysis.
9 To summarize, Company subtransmission planning engineers analyze the
10 subtransmission system by modeling multiple electric system scenarios across each
11 individual subtransmission line with all possible contingency situations
12 (unintentional equipment shutdowns) assessed. These analyses are conducted
13 utilizing industry-standard modeling software with individual substation loads
14 submitted by Company SMEs and the models used by the Midcontinent
15 Independent System Operator (MISO).

16

17 The analysis performed revealed that one-third of the circuits on the
18 subtransmission system has a thermal and/or a voltage planning criteria violation.
19 A sample of this data was provided in discovery response U-21534 MNSCDE-
20 5.5a(S1) in the instant case and included in Exhibits A-50, Schedule OO1 and A-
21 50, Schedule OO2.

22

23 The significance of a violation is that a circuit experiencing a thermal and/or voltage
24 planning criteria violation has capacity limitations as additional load can't be added

Line
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1 in a permanent and/or temporary bases without a risk of equipment damage that can
2 result in cascading outages, impacting a significant number of customers.

3

4 **Q35. What is a subtransmission planning criteria thermal violation?**

5 A35. Thermal violations, a subset of planning criteria violations, occur when analysis
6 indicates that subtransmission equipment overloads will likely lead to the
7 overheating of equipment, resulting in permanent damage or failure of the
8 equipment, based on DTE's Subtransmission Planning Criteria and Equipment
9 Thermal Loading Policy. The overloading conditions are a result of general load
10 growth over time.

11

12 For system day-to-day normal operating conditions, the subtransmission equipment
13 can be loaded up to 100% of its normal rating without damaging equipment or
14 causing outages to customers. When loaded above 100%, it's considered a thermal
15 violation. For example, the subtransmission trunk line TRK4217 has a normal
16 rating of 19MVA, yet it currently serves 21.8 MVA of load under normal operating
17 conditions, meaning this cable is loaded to 115% of its normal rating. This day-to-
18 day over capacity condition is leading to the degradation of the cable life.
19 Additionally, when the load peaks above the day-to-day normal rating, such as on
20 a hot summer day, there is a further increase in the probability of failure. The
21 Company has proactively identified and developed projects to address all day-to-
22 day over capacity conditions.

23

24 For emergency conditions, which is when a single contingency event occurs for a
25 limited period of time, the subtransmission equipment can be loaded to 90% of its

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1 emergency rating. When equipment is exceeding 90% of its emergency rating, load
2 shed (or intentional customer outages) must be initiated to protect the equipment
3 from failure due to thermal loading and overheating.

4
5 In a typical case where two subtransmission lines are feeding a distribution
6 substation and one of them is interrupted due to a failure or outage event, the other
7 subtransmission line can only serve load that is up to 90% of its emergency rating
8 on a temporary basis while the first line is being restored. If the combined load of
9 the distribution substation exceeds 90% of the emergency rating of the remaining
10 subtransmission circuit, load will be intentionally interrupted to prevent equipment
11 damage and additional cascading outages.

12

13 **Q36. Can you detail an example where a thermal violation impacted system**
14 **redundancy?**

15 A36. Yes, the Trunk 359 example below demonstrates a thermal violation where the
16 Company had to shed load until mobile equipment was deployed.

17

18 Example: Trunk 359

19 On September 4, 2023, there was a cable failure on Trunk 4338, which serves
20 distribution substation transformer 1. The load normally served from distribution
21 substation transformer 1 was automatically transferred to distribution substation
22 transformer 2, which is served from Trunk 359. Trunk 359 then exceeded its
23 emergency rating while it carried all the load of the distribution substation
24 (transformers 1 and 2). As a result, all the circuits out of the distribution substation
25 were rotated through outages (load shed) by the System Operator, until five large

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1 portable generators delivered and installed to relieve load on September 6th. Final
2 repairs were completed on September 16th, and the circuits were returned to their
3 normal state.

4

5 As shown in Figure 3, this event resulted in over 5,000 customers experiencing over
6 1.5 million customer minutes interrupted for approximately two days. A project
7 has been developed to replace the cable of Trunk 359 to increase the circuit rating
8 and prevent future load shedding for this single contingency event, loss of Trunk
9 4338.

10

11 **Figure 3 : Distribution Substation Outages from September 4, 2023**

12

Event

Summary of Haskell Load Shed between 9/4/2023 & 9/6/2023 to Mitigate Overload on TRK 359			
Circuit	Total Customers	Outage Duration (minutes)	Total Customer Minutes between 9/4/2023 & 9/6/2023
DC 1	860	382	328,520
DC 2	582	248	144,336
DC 3	1106	210	232,260
DC 4	538	536	288,368
DC 5	610	496	302,560
DC 6	870	280	243,600
DC 7	629	42	26,418
Total Customers Impacted: 5195		Total Customer Minutes Interrupted: 1,566,062	

13

14 This event is just an example of the conditions that exist on the subtransmission
15 system, highlighting that redundancy and planning to mitigate single contingency
16 scenarios is critical, and Subtransmission Redesign and Rebuild projects to support
17 this type of event are not discretionary.

18

19

20

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1 **Q37. What is a subtransmission planning criteria voltage violation?**

2 A37. A voltage violation is another sub-category of planning criteria violations. This
3 occurs when subtransmission system conditions lead to a voltage level that is
4 outside of the +/- 5% of the intended nominal system voltage, as is required by the
5 ANSI C84.1 standard. To satisfactorily serve the Company's customers, a 40 kV
6 subtransmission circuit needs to maintain the system voltage between 38 kV (95%)
7 and 42 kV (105%). If the system voltage falls outside of this required range, the
8 customers' equipment (washer, dryer, refrigerator, water heater, furnace, garage
9 door opener, and lights) will not function properly and may cause damage operating
10 at these levels.

11

12 Thus, when the subtransmission circuit voltage falls outside of this required range,
13 it is a violation of the voltage planning criteria under normal operations. Under
14 emergency contingency conditions, where a subtransmission circuit has to carry
15 additional load, the Company does allow subtransmission circuits to be operated as
16 low as 92% of nominal voltage for a short period of time to prevent outages to
17 customers. The Company's voltage violation criteria under emergency single
18 contingency conditions is 92% to 105% of the nominal voltage.

19

20 Voltage violations commonly occur when loading on the system has increased. This
21 could happen during normal operation, such as when load growth from new homes
22 and businesses move into an area and connect to the electric grid, increasing the
23 local electric demand in the area. The voltage violation could also occur in a
24 contingency state when load has been increased on portions of the system due to

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1 temporary load transfers that occur to keep customers energized in the event of
2 equipment failure.

3

4 **Q38. Can you detail an example where a voltage violation could impact system**
5 **redundancy?**

6 A38. Yes, the Northeast Area Transformer Project example below demonstrates how a
7 voltage violation could impact system redundancy.

8

9 Example – Northeast Area Transformer Project

10 The Northeast Area Transformer is a critical source to serving load for the northeast
11 region of DTE's service territory. If an outage were to occur on the Northeast Area
12 Transformer or its associated 120kV or 40kV equipment, there are 29 Substations
13 affecting approximately 37,000 customers, that will have voltage below 92% of
14 nominal voltage, thus creating the emergency voltage violation condition. DTE
15 would be forced to shed load to protect DTE's and customer's equipment until
16 voltage can be restored to our minimum criteria of 92%.

17

18 To resolve this planning criteria violation, a project is underway to install a second
19 120-40kV transformer at the Northeast Area station to provide redundancy for this
20 critical source.

21

22 **Q39. How does the Subtransmission Redesign and Rebuild program improve**
23 **resiliency in the face of storms, in addition to reliability?**

24 A39. Improved resiliency is an additional benefit of the Subtransmission Redesign and
25 Rebuild program. As the Company implements these projects, it looks for

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1 opportunities to relocate subtransmission circuits from often inaccessible deep and
2 railroad right-of-way (ROW) locations to truck accessible road ROW. In addition
3 to significantly reducing the subtransmission circuit's exposure to tree damage, this
4 greatly improves the line crew's access to the circuit from bucket trucks, leading to
5 reduced cost and timing for tree trimming, maintenance and equipment
6 replacement. When there is an outage event, it will reduce the patrol time allowing
7 for quicker restoration.

8

9 In addition to improving accessibility, the Subtransmission Redesign and Rebuild
10 program rebuilds the identified segments to the Company's latest, more resilient
11 construction standards by using steel poles, stronger conductor, stronger clamp top
12 insulators, and shield wire for improved lightening protection. This allows the
13 newly constructed subtransmission circuits to be more durable and resilient during
14 severe weather events.

15

16 Witness Stephens agrees that larger conductor and steel poles are less susceptible
17 to storm damage⁴⁰. However, he then deemed that this improved resiliency is not
18 necessary since wind and ice comprised just 1.3% of subtransmission outages from
19 2019 to 2023 per his calculations, and shown in Figure 4 below. First, wind and
20 ice are not the only causes of storm damage. Secondly, while it is true that ice
21 historically has not occurred frequently in the Company's territory, when it happens
22 it often results in large, catastrophic storm damage. As an example, there was a
23 once in a 50-year ice event in 2023 that dramatically impacted the Company's
24 system, including subtransmission equipment. As noted in more detail in Company

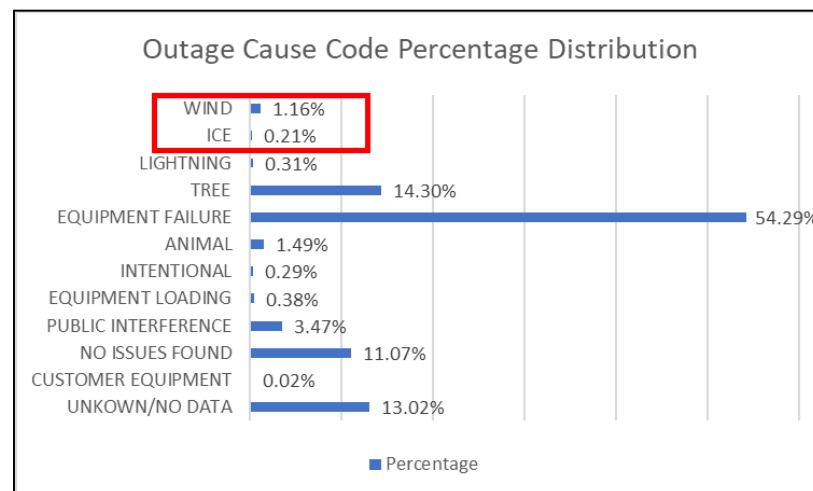
⁴⁰ Stephens DT, p. 34, lines 12 – 13

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Witness Kryscynski's direct testimony, page 22, lines 9 – 11, the Company's service territory has been experiencing more frequent and increasing wind speed weather events.

In his testimony, Witness Stephens does not consider the additional types of outages that can be caused from wind/weather-related damage which can be resolved by rebuilding circuits to the updated standard. Wind/weather-related damage can include broken cross arms and braces, downed conductor, broken poles, and damage from trees. Assuming that approximately 1/4 of equipment failure cause codes are weather related damages and adding wind, ice, lightning, and tree cause codes, Figure 5 below demonstrates that this combination adds up to ~ 30% of subtransmission outages. This shows the need to have a more durable and resilient subtransmission system.

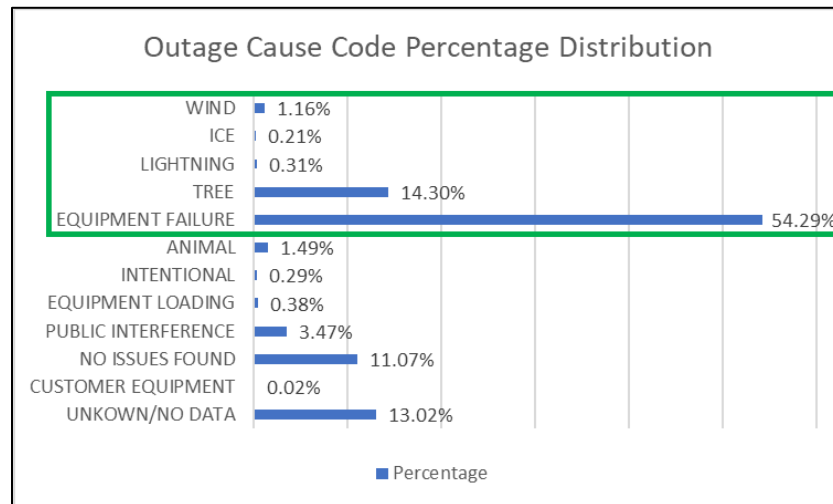
Figure 4: Witness Stephens' Cause Code Selection



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Figure 5: Revised Cause Code Selection



2

3 **Q40. Witness Stephens states “the question is, on which subtransmission circuits**
 4 **are the risks the greatest, and how quickly should they be addressed⁴¹?” How**
 5 **does the Company determine priorities and timing when selecting circuits for**
 6 **Subtransmission Redesign and Rebuild program?**

7 **A40.** As stated in my direct testimony on pages 55 through 56, Company subtransmission
 8 engineers prioritize projects to address the thermal and/or voltage planning criteria
 9 violations based on the violation severity and customer impact. When prioritizing
 10 a subtransmission project for investment, the engineers evaluate the system risks,
 11 including the amount of load over the equipment’s rating in normal day-to-day
 12 configuration, the amount of load loss in a single contingency scenario, the severity
 13 of the voltage violation, the need for future capacity based on confirmed load
 14 projections, and the reliability performance for each circuit, with the resultant
 15 project benefits of mitigating or eliminating these risks. All planning criteria
 16 violations are required to be addressed, and the above methodology determines

⁴¹ Stephens DT, p. 36, lines 4 – 6

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1 which will be resolved first. The prioritized subtransmission project list will be
2 further prioritized against other company investments needs using the GPM model.
3

4 **Q41. Does the Company consider alternatives while developing Subtransmission**
5 **projects?**

6 A41. Yes, it does. The Subtransmission Planning Engineers lead multiple technical
7 reviews during the detailed engineering scope development phase to evaluate project
8 options and determine the most cost-effective solution. These technical reviews
9 include the evaluation of alternatives to the project, with the final scope approval
10 determined by senior level technical planning experts before the project can move
11 to the next phase. Multiple field visits are conducted in early stages of the project
12 with a cross functional team, including those who work on the construction and
13 maintenance of the equipment, to identify potential implementation risks. Project
14 scope alternatives and mitigation plans are developed to address risks, minimize
15 costs and optimize the benefits of the projects.
16

17 **Q42. How do you respond to Witness Stephens' claim that the Company has not**
18 **identified alternatives for some of its proposed subtransmission projects?**

19 A42. In addition to the aforementioned technical review and subsequent field visits
20 which lead to the consideration of project scope alternatives, Company Witness
21 Kryscynski's response to MSNCDE-8.5a in the instant case, included in Exhibit A-
22 50, Schedule OO3, further describes the Company's review of project alternatives.
23 In this response, Witness Kryscynski states:
24

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“During initial planning stages of large projects, multiple design options are often explored as different engineering groups collaborate to brainstorm high-level solutions. An initial set of solutions will be narrowed down if some solutions are determined to be unsuitable for reasons such as, but not limited to, the following:

- Does not adhere to DTE engineering standards and practices
- Availability or lead time of equipment is too long
- An extended outage duration is required to complete project
- Alternative is overly complex and not markedly better than other options”

Q43. In addition to the general concerns you’ve noted, does Witness Stephens recommend the disallowance of any specific projects that are part of the Subtransmission Redesign and Rebuild Program?

A43. Yes. He recommends the disallowance of three specific subtransmission projects: Tie 4105 Phase 3, Tie 4105 Phase 4, and Trunk 3905.

~~Q44. What is the scope of the Tie 4105 project?~~

~~A44. Tie 4105 is a 62-mile circuit serving 7 substations (3,546 customers) in the rural part of the Company’s service territory. To mitigate degrading reliability, the project is to rebuild and relocate approximately 35 miles (50%) of this circuit. The construction will include equipment designed to the new, more resilient standards, and relocation from deep, heavily treed ROW to more truck accessible road ROW, as shown in Figures 6 and 7 below.~~

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~~Figure 6 : Tie 4105 Existing Wood Poles vs. New Steel Poles~~

This project will improve circuit reliability and accessibility by rebuilding the segment to updated standards and relocating it out of deep ROW

Existing 40kV Construction on Tie 4105



- Tie 4105 currently has wood poles and minimal lightning protection, leading to poor reliability
- Circuit is located in deep ROW and railroad ROW, leading to poor accessibility and more exposure to tree related outages

New 40kV Standard for Tie 4105



- The Tie Line is currently being rebuilt with steel poles and 636 AL OH wire with lightning protection, leading to improved reliability
- Circuit is being relocated to road ROW, and will lead to better accessibility and a reduction on tree related outages

2

3

~~Figure 7: Tie 4105 Existing Route vs. New Route Along Road ROW~~

1. The existing route of Tie 4105 is not truck accessible requiring foot patrols for outages.

2. Railroad flag man are required for access to equipment along Railroad ROW.

3. Existing poles are in farm fields limiting accessibility for maintenance and increasing restoration times when a failure occurs.

4. Some sections of Tie 4105 are in heavily treed easements, increasing the potential for trees inside and outside our easement to cause outages on Tie 4105.



Existing Route of Tie 4105 along Railroad in Deep Easement

New Route of Tie 4105 along Road ROW

4

5 ~~Q45. Why is it necessary to complete the Tie 4105 project?~~

6 ~~A45. As shown in Table 2 below, Tie 4105 reliability performance began to degrade~~
7 ~~further in 2019. The substations served from Tie 4105 experienced frequent~~

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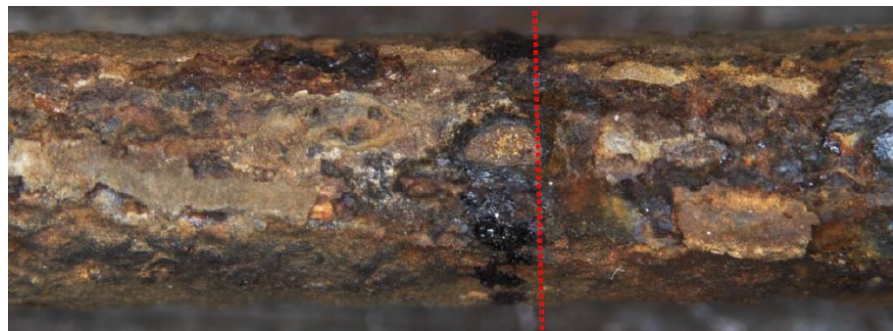
1 outages. This resulted in escalated complaints by customers and communities to the
2 Company and the Michigan Public Service Commission (MPSC).
3

4 **Table 2 ~~Tie 4105 Initiative Reliability Performance Improvement~~**

Year	Total Momentary Outages on Tie 4105	Total Sustained Outages on Tie 4105	Total Customer Minutes from TIE4105 Outages	
2015	3	3	4,530,656	
2016	10	3	3,060,346	
2017	9	4	4,671,876	
2018	10	3	1,804,047	
2019	9	7	9,990,554	
2020	1	7	3,798,693	
2021	4	6	7,641,562	
2022	5	7	1,155,311	
2023	2	4	365,832	Tie 4105 Phase 1 Completed

5
6 Seventy percent of the poles on Tie 4105 are beyond their life expectancy. Testing
7 of the conductor samples from Tie 4105 demonstrated reduced tensile strength and
8 the steel core zinc layer was no longer present to prevent further oxidation &
9 corrosion, as shown in Figure 8. If not addressed urgently, this will lead to
10 conductor failure and a much-reduced resiliency during severe weather events, as
11 shown in Figure 9.

12
13 **Figure 8 : Existing Tie 4105 Steel Core of 3/0 ACSR conductor showing**
14 **corrosion**



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2

Figure 9: Existing Tie 4105 3/0 ACSR reduced tensile strength



3

4

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12

~~Demonstrating the need for greater resiliency, data from the FALLS® lightning database indicates that there were 65 lightning strikes within a half mile of Tie 4105 from January 2016 through December 2018 shown as blue dots on the map in Figure 10 below. Lightning within a half mile is capable of generating induced impulses on power lines. Of these 65 lightning strikes, the data indicates there were 13 lightning strikes during this time interval that were direct strikes to the lines or immediately adjacent to them. See Figure 11 for the date, time, polarity, and intensity of the lightning events.~~

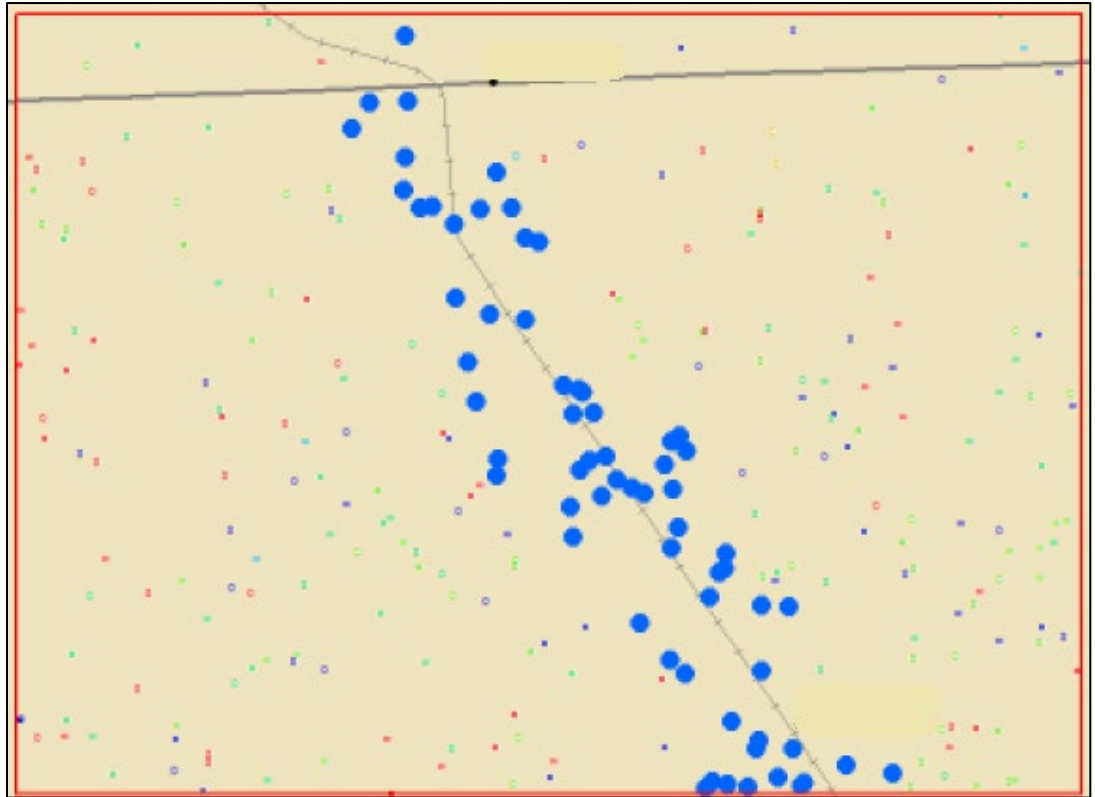
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~~Figure 10: Lightning strikes within 5 miles of Tic 4105 between~~

2

~~2016 and 2018~~



3

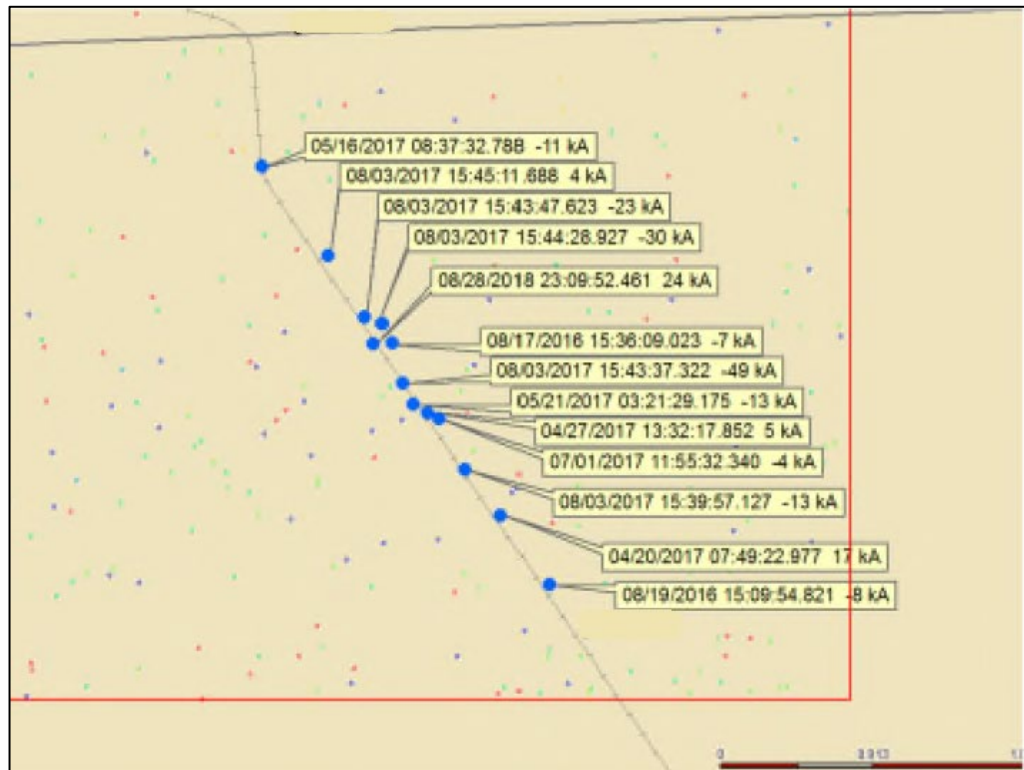
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Figure 11: Lightning activity within a half mile of Tie 4105 between

2

January 2016 and December 2018



3

4

This project is currently underway, and it will be implemented in phases. As shown in Table 1 above, Tie 4105 reliability performance began to show improvements after the first phase of the project was completed in early 2023.

7

8

Q46. What is the scope of the Trunk 3509 project?

9

A46. The Trunk 3509 project's scope is to upgrade about 1.2 miles of existing underground cable to the current standard higher capacity, more reliable 650 EPR cable. In addition, the circuit connection will be moved to a new station position which involves installing new station equipment (breaker, disconnects, and relay).

12

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~~1 Trunk 3509 is a 5-mile circuit serving 4 substations (2,539 customers including a~~
~~2 major hospital and trauma center). The circuit has a unique configuration where it~~
~~3 shares the station position/equipment with another circuit (Trunk 3508). This~~
~~4 configuration increases the outage exposure on Trunk 3509 and limits its capacity,~~
~~5 as the station equipment must carry the load of two circuits. Additionally, both~~
~~6 circuits must be shutdown to perform routine maintenance on station equipment~~
~~7 like the breaker.~~

8

9 **~~Q47. Why is it necessary to complete the Trunk 3509 project?~~**

~~10 A47. Trunk 3509 is experiencing thermal overload planning criteria violations in both~~
~~11 normal day-to-day and single contingency scenario. To protect Trunk 3509 from~~
~~12 equipment damage during a single contingency scenario, the Company has to~~
~~13 implement an emergency load control scheme at one of the substations. If this~~
~~14 emergency load control scheme is triggered, all of the customers served from the~~
~~15 substation would experience an outage until the failure is fixed or until further~~
~~16 operation solutions can be implemented (if available). Also, due to the existing~~
~~17 thermal overload planning criteria violation, additional customer load cannot be~~
~~18 added to TRK 3509 limiting growth in the area.~~

19

~~20 The objective of the Trunk 3509 project is to upgrade the limiting equipment that~~
~~21 is causing this thermal overload planning criteria violation. By doing this work, we~~
~~22 are alleviating thermal loading violations, and the possibility of shedding customer~~
~~23 load during a single contingency event. Additional benefits include increased~~
~~24 capacity on Trunk 3509, improving operational flexibility, and reducing outage~~
~~25 exposure on Trunk 3509 by giving the circuit its own station position.~~

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1 **Q48. In addition to the scope and benefits information you provided for the Tie 4105**
2 **and Trunk 3509 projects, does your rebuttal testimony include more**
3 **information on scope, project drivers, costs and benefits for subtransmission**
4 **projects?**

5 A48. Yes. In my testimony above, Q&A 44 to Q&A 47, I have further explained in detail
6 the Tie 4105 and Trunk 3509 projects and why it is necessary to complete them.

7

8 In addition, Exhibit A-23, Schedule M6 provides detailed project drivers, required
9 scope and associated benefits for each Subtransmission Redesign and Rebuild
10 project.

11

12 **Q49. Do you have an additional concern with AG-MN Witness Stephens'**
13 **recommendation on disallowance of subtransmission projects?**

14 A49. Yes. Witness Stephens states on page 37 lines 8-9 of his testimony that "I
15 recommend that the Commission disallow cost recovery on all such projects that
16 the Commission has not already approved. In 2024 and 2025, DTE projects
17 bringing three such projects online, and adds them to rate base in the instant
18 application. The three projects – Tie 4105 Phase 3, Tie 4105 Phase 4, and Trunk
19 3509 – total \$28.15 million⁴²." He seems to indicate that the three named projects
20 were not previously approved by the Commission, that is incorrect. These projects
21 were 1) included in case No. U-21297, Exhibit A-12 B5.4, page 9 of 21, line 17
22 (Tie 4105) and line 21 (Trunk 3509), and 2) were in fact approved, not disallowed
23 in the Commission Order⁴³.

⁴² Stephens DT, p. 37, lines 8 – 11

⁴³ MPSC Order in Case No. U-21297, dated December 1, 2023, p. 106. Regarding Subtransmission Redesign & Rebuild (Schedule B5.4, p. 11, line 114 [total of all subtransmission redesign and rebuild

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1

2

In conclusion, The Company recommends that all the Subtransmission Redesign and Rebuild projects be approved in the instant case and in the IRM including program years 2026 and 2027, as explained in Witness Foley's rebuttal testimony, page 21, line 18 through page 24, line 23.

6

7

Part III: Strategic Undergrounding Program

8

9

Rebuttal Topic 4: AG-MN Witness Stephens' claim regarding the Company's

10

undergrounding projects

11

Q50. What recommendations are made by Witness Stephens in the instant case regarding undergrounding projects?

12

13

A50. Witness Stephens recommends the disallowance of the Company's underground pilot program, \$15.6 million in 2024 and \$16.0 million in 2025⁴⁴. Additionally, he stated that undergrounding is expensive and "not the panacea many perceive it to be⁴⁵."

14

15

16

17

18

Q51. Why did the Company start an underground pilot project?

19

A51. Per Case No. U-20169, the Company was asked to explore pilot projects to eliminate 4.8kV ungrounded delta rear-lot overhead infrastructure and its associated hazards⁴⁶. With the focus on reducing the safety hazard of a downed

20

21

projects, including Tie 4105 and Trunk 3509]) states "the Commission finds the ALJ's recommendation to reject the proposed disallowances to be well-reasoned and supported by the record. The Commission adopts the ALJ's findings and conclusions on this issue and approves the 11-month bridge period and test year amounts."

⁴⁴ Stephens DT, p. 43, lines 4 – 11

⁴⁵ Stephens DT, p. 42, line 16

⁴⁶ MPSC Order in Case No. U-20169, dated January 18, 2019, p. 4

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1 conductor of a rear-lot 4.8 kV ungrounded delta circuit, the Company initiated the
2 first pilot on Appoline DC1346 (Appoline).

3

4 **Q52. Why is the Company interested in continuing to underground circuits?**

5 A52. In addition to the safety benefits for the public and Company employees, the
6 Company is interested in undergrounding because: 1) undergrounding improves
7 reliability and resiliency due to the tree impacts to overhead lines caused by
8 increasingly frequent and severe storms and aged overhead infrastructure, 2) over
9 the life cycle of the undergrounding assets, the initial comparatively higher
10 construction costs are balanced by reduced maintenance costs by eliminating the
11 need for tree trimming and pole top maintenance programs, 3) reduction of reactive
12 cost to repair storm damage and increased restoration time, 4) to take advantage of
13 this unique opportunity to be able to underground portions of circuits as it converts
14 its aged 4.8kV, and in some cases gain efficiencies where there is other construction
15 work occurring in the area to improve the system resiliency instead of just the like-
16 for-like replacement of existing overhead infrastructure, 5) other utilities are using
17 undergrounding to harden their system to be more resilient, and 6) customers and
18 communities are reaching out to the Company asking to underground utility lines
19 and eliminate their associated poles. City of Ann Arbor Witness Stults states “Ann
20 Arbor has indicated its interest in having DTE do undergrounding pilots in the
21 City⁴⁷.” Witness Bunch, representing, The Michigan Municipal Association For
22 Utility Issues (MAUI), states that “Many local governments are keenly interested
23 in the undergrounding of electric infrastructure as a reliability measure, the high
24 costs of which might be reduced were projects scheduled to coincide with local

⁴⁷ Stults DT, p. 30, line 20

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1 road, water, sewer and other projects⁴⁸.” Witness Watts, representing Soulardity
2 And We Want Green, Too (DAAO), states “DTE should update our power lines
3 from overhead lines to underground lines to reduce the number of outages⁴⁹.”
4

5 **Q53. Does the Company agree with Witness Stephens’ summarization of the**
6 **Strategic Undergrounding pilot projects?**

7 A53. In part. On a high level, the pilot projects replace rear-lot overhead 4.8kV
8 ungrounded delta infrastructure with underground infrastructure, eliminating the
9 safety hazard associated with a downed conductor. However, Witness Stephens
10 does not include the key point that Appoline and Buffalo-Charles projects are pilots
11 that the Company is using to learn from. This approach allows the Company to
12 develop processes and gain efficiencies on early, smaller projects to reduce
13 implementation cost before larger-scale undergrounding is rolled out as a broader
14 program. These pilot projects also allow the Company to understand potential cost
15 efficiencies that could be achieved by jointly working with municipalities or other
16 utilities. Using this measured approach, the Company can determine when and
17 where this design option can be utilized most effectively.
18

19 **Q54. Does the Company agree with Witness Stephens’ assessment of reliability and**
20 **safety concerns of undergrounding?**

21 A54. No. Witness Stephens states, “underground lines are subject to reliability risk from
22 flooding and careless excavation, and subject to safety risk from both excavation
23 and contact voltage⁵⁰.” Addressing his first concern of flooding as a safety risk,

⁴⁸ Bunch DT, p. 76, lines 19 – 22

⁴⁹ Watts DT, p. 10, lines 13 – 14

⁵⁰ Stephens DT, p. 42, lines 14 – 15

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1 underground cable and equipment are specifically designed to be able to withstand
2 flooding. Currently, approximately 30% of the Company's system is underground.
3 The circuits that are entirely underground have a much better reliability
4 performance than circuits that are overhead. Using 2023 All Weather data,
5 completely undergrounded circuits had a 77% improved SAIFI performance over
6 completely overhead circuits.

7

8 It is true that careless excavation is a risk to reliability and safety. However, this
9 risk is being effectively mitigated. Municipalities require a permit and that all other
10 utilities are marked/identified before digging or starting construction. The
11 Company believes that careless excavation is a very low risk when compared to the
12 safety risk associated with a downed conductor.

13

14 **Q55. Does the Company agree with Witness Stephens' recommendation to disallow**
15 **the full amount for the Strategic Undergrounding Pilot program?**

16 A55. No. The Company believes that undergrounding brings a set of unique benefits to
17 our customers. Undergrounding is an alternative to traditional overhead
18 infrastructure design, one that eliminates the associated safety risk associated with
19 downed conductor and other overhead equipment. Undergrounding provides the
20 benefit of reducing emergent reactive costs and is the most resilient option for
21 severe weather-related events. Due to these benefits of undergrounding, the
22 Company has developed plans to conduct additional pilots, in order to refine its
23 process and continue to focus on reducing implementation costs. The Company
24 recommends that the \$15.6 million in 2024 and \$16.0 million in 2025 for these vital
25 underground pilot projects in the instant case be approved.

26

Line
No.

1 **Part IV: General Infrastructure Redesign & Modernization Rebuttal Points**

2

3 **Q56. Have any intervenors requested that the MPSC make additional disallowances**
4 **or direct the Company to undertake any specific activities related to**
5 **distribution infrastructure or processes?**

6 A56. Yes, intervenors have suggested a collection of conceptual proposals listed in Table
7 3 below for the Company to undertake. However, as a group these suggested
8 directives are undefined and largely lack the detail requisite to be thoroughly
9 considered. The time, resources, costs, and other inputs necessary to begin these
10 tasks have neither been discussed nor even listed; the resultant values have not been
11 calculated nor considered; alternatives have not been identified nor compared. In
12 an attempt at brevity, the Company is not rebutting all the unsupported and
13 misguided suggestions individually. All of these requested directives should be
14 denied.
15

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1

Table 3 General Rebuttal Topics

Witness	Rebuttal Point	Rebuttal
ABATE – York	Regarding distribution capital strategic replacements, on page 31, lines 6-11 of Witness York’s direct testimony, she recommends that “the Commission allow only the projected capital expenditures associated with projects that are expected to be in-service during the bridge period and projected test year.”	Company Witness Uzenski’s direct testimony, page 70, lines 19-25 (Q&A 135) states that for capital expenditures on projects that will not be in service during the projected test period do not have a current revenue requirement. Additionally, the Commission found Witness York’s similar proposed adjustments in case No. U-21297 unpersuasive by stating that “the Commission does not find that the question of whether a project will be completed within the test year is dispositive as to whether that project belongs in rate base. ⁵¹ ” The Company recommends the Commission disregard Witness York’s recommendation in the instant case.
MNSC - Woolley	On page 2, line 15 – page 3, line 2 of Witness Woolley’s direct testimony, he provides his principal conclusions on transforming aging that: “- Nominal transformer ratings don’t capture the physics of transformer aging, and they should not be the sole basis for transformer sizing decisions;	The Company offers the following brief rebuttal points to Witness Woolley’s principal conclusions on transformer aging: - Thermal loading and ambient temperatures is only one of several factors including thru-faults and voltage impulses

⁵¹ MPSC Order in Case No. U-21297, dated December 1, 2023, p. 84

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	- The physics of transformer aging lends itself to a more thorough and rigorous analysis that can be done with relatively simple modeling, which I demonstrate; - Transformer aging occurs almost entirely in summer months (June through August), while almost none happens in the winter (December through February); and - Increasing load during winter months is unlikely to compromise the health of existing transformers, which are typically sized to accommodate summer peaks.”	(switching surges, lightning, etc.) that can lead to transformer aging; - The Company uses IEEE standards as the basis for transformer ratings and aging expectations; - The Company acknowledges that a transformer experiences “accelerated” aging in extreme heat due to high load and ambient temperature, but if a transformer were to be fully loaded for 1 year in a cold/winter climate, it would have 1 year worth of life of the transformer consumed as well.
AA – Stults	On page 26, lines 9 – 11 of her testimony, Witness Stults recommends that contributions in aid of construction (CIAC) be no more than it would be if a site were served by a 13.2kV system by arguing that the Company should cover the costs for increasing the capacity in an area by 2.5 times before any CIAC is charged to a developer for increased capacity. She argues that this is because much of the city is served by a 4.8kV system that generally does not have as much capacity as areas served by 13.2kV on page 24, line 23 of her testimony.	In Rebuttal Issue 16 of his rebuttal testimony, Company Witness Hill addresses the CIAC component of Witness Stults’ recommendation. Regarding her claim that 4.8kV systems do not have as much capacity as a 13.2kV system: - It is true that a 4.8kV circuit has less capacity than a 13.2kV circuit. This is why more 4.8kV circuits are needed to serve an area versus a 13.2kV circuit. - Through conversions, a 13.2kV circuit replaces 2 to 3 4.8kV circuits (thus reducing equipment needed). - Adding new load to a circuit is not dependent on voltage, but the existing

Line
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		load on the particular circuit. A loaded 13.2kV circuit will also need additional modifications to serve the new load, just like a 4.8kV circuit.
AA – Stults	On pages 30 – 31 of her testimony, Witness Stults describes the City of Ann Arbor’s interest in partnering with the Company to conduct undergrounding pilots, but states that the Company has not taken advantage of this opportunity to collaborate with the city.	The Company has been engaged with the City of Ann Arbor staff. In October of 2023, the Company worked with Ann Arbor to incorporate an undergrounding project to accommodate a city paving project. Additionally, a Regional Affairs Manager with the Company has established bi-annual meetings with Ann Arbor to review future infrastructure projects within city limits. Individuals included on these meetings include, but is not limited to, Skye Stewart, Andrea Wright, Nicholas Hutchinson, and Nicholas Bayley. A second opportunity to align infrastructure projects has been identified and is pending engineering review for late 2024.

1

2 **Q57. Does this conclude your rebuttal testimony?**

3 A57. Yes, it does.

1 JUDGE WALLACE: And then as far as
2 exhibits go, we have Exhibit A-12 Schedule B5.4; Exhibit
3 A-23 Schedule M6; A-23, Exhibit A-23 Schedule M11;
4 Exhibit A, was it 23 or 24, M13, was that 23?

5 MS. JOHNSON-BACON: Yes, your Honor.

6 JUDGE WALLACE: O.K. Exhibit A-23
7 Schedule M13; Exhibit A-28 Schedule R1; Exhibit A-50
8 Schedule OO1; Exhibit A-50 Schedule OO2, and that is CEII
9 Confidential Exhibit; and lastly, Exhibit A-50 Schedule
10 OO3, so we will admit those once we've completed binding
11 in the rest, all of the rest of the Company's case.

12 Mr. Bzdok -- let's see, what time is it,
13 9:25 -- so you have about a half an hour before we need
14 to go take a break. So please proceed, Mr. Bzdok.

15 MR. BZDOK: Thank you, your Honor.

16 COURT REPORTER: Before we start -- I'm
17 sorry. Mr. Deol, I don't know if you're further away
18 from the mic or if you can get closer to the mic or keep
19 your voice up, because you're much quieter than Ms.
20 Johnson-Bacon.

21 MS. JOHNSON-BACON: You know, everyone
22 says that.

23 COURT REPORTER: No, you're clear, loud
24 and clear. Thank you.

25 THE WITNESS: Is this better?

1 COURT REPORTER: Yes. Thank you.

2 MR. BZDOK: May I proceed, Lori?

3 COURT REPORTER: Yes. Thank you. Sorry.

4 MR. BZDOK: May I proceed, your Honor.

5 JUDGE WALLACE: Yes, you may, please.

6 MR. BZDOK: Thank you.

7 CROSS-EXAMINATION

8 BY MR. BZDOK:

9 Q Good morning, Mr. Deol.

10 A Good morning.

11 Q We spoke for some time last year in Case U-21297; do you
12 recall that?

13 A Yes, I do.

14 Q In that case, and in this case, you sponsor Company's,
15 the Company's capital expenditures for certain
16 distribution programs; is that right?

17 A Yes.

18 Q One of those is conversions of 4.8 kV and some other
19 circuits to a higher voltage of 13.2 kV; is that right?

20 A Correct. Yeah, it is 4.8 kV system and the 8.3 kV
21 system.

22 Q And the other program that you sponsor is subtransmission
23 redesign and rebuild; is that right?

24 A Correct.

25 Q O.K. I am going to talk to you at some length today

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1 about those two programs, and we'll start with
2 conversion. I'd ask you to take a look at your Exhibit
3 A-12 Schedule B5.4, I guess your pages of that exhibit,
4 and specifically page 16.

5 A O.K., I'm there.

6 Q O.K. And can you hear me O.K.?

7 A Yes.

8 Q O.K. So on page 16, line 115, you have -- you have
9 listed a category summary for conversions, which is the
10 sum of certain other lines. Do you see that?

11 A Yes.

12 Q And you have a bridge period amount for calendar year
13 2024 of \$361,086,000; is that right?

14 A Correct.

15 Q And then you have a test year projection of \$78,755,000
16 for that category; is that right?

17 A Correct.

18 Q And in addition to -- so these would be rate base capital
19 expenditures -- capital expenditures for conversion
20 projects that will be included in rate base; is that
21 right?

22 A Correct.

23 Q And are these inclusive of the City of Detroit
24 Infrastructure or CODI projects, these amounts?

25 A Yes, this includes the CODI program.

1 Q O.K. In addition to the rate base cap ex for
2 conversions, there is, there are also conversions
3 projects that are being proposed for funding through the
4 infrastructure recovery mechanism or IRM; is that right?

5 A That's correct.

6 Q I'm looking at Mr. Foley's testimony, Table 1, page 54,
7 but I'd welcome you to look at any source you that might
8 have just to confirm that the proposed amount for
9 conversions via the IRM in 2025 is \$185.8 million?

10 A Yes. Are you referring to Witness Foley's table on page
11 9 in his testimony?

12 Q Sort of. So Mr. Foley filed testimony, and I think it
13 probably was on page 9 originally, then he filed revised
14 testimony where he adopted Adella Crozier's direct
15 testimony, which pushed it way back to page 54. But
16 you're looking at a Table 1, Proposed IRM Investment
17 Level in millions of dollars?

18 A Yes.

19 Q O.K. So I think we're on the same page even if we're not
20 literally on the same page.

21 A O.K.

22 Q O.K. So \$78.8 million of rate base cap ex for
23 conversions in 2025 plus \$185.8 million for IRM
24 conversions in 2025 puts us roughly in the neighborhood
25 of \$264.6 million for conversions total in 2025; would

1 you -- does that sound right?

2 A Subject to check, I guess. It would be the addition of
3 the two.

4 Q That's generally consistent with your understanding as
5 the sponsor of the conversions, that that's in the
6 ballpark of what the Company expects to invest in 2025?

7 A Yes.

8 Q O.K. One of the -- let's talk about circuit loading.

9 A O.K.

10 Q What is circuit loading?

11 A Loading on a particular circuit.

12 Q And what does that mean, high level?

13 A The customer load that the Company or that circuit
14 provides support for those customers.

15 Q In the -- do you have access to the SharePoint site for
16 this case?

17 A Yes, I do.

18 Q O.K. So in the SharePoint site under the Company's
19 folders, and specifically under your folder, there's a
20 folder called MNSC hearing exhibits for Deol.

21 A O.K., I'm there.

22 Q O.K. If you open that up, there is proposed Exhibit
23 MEC-77, which is Discovery Response MNSCDE-19.21a-f. Do
24 you see that?

25 A I haven't found it yet. Is it 77 you said?

1 Q Yeah. Have you been in the site for a while?

2 A Yes.

3 Q Try refreshing it, I just popped it in there.

4 A O.K., I found it.

5 Q O.K., great. So open that up, if you would, please.

6 A O.K.

7 Q What this -- what the first two pages, subquestion (a)
8 and the response provide in this exhibit is a list of
9 circuits the Company proposes to converts from a lower
10 voltage to 13.2 kV during the projected test year and the
11 IRM Plan years; is that right? Are you able to answer my
12 question, or do you need me to repeat it?

13 MS. JOHNSON-BACON: I think he did answer
14 your question.

15 COURT REPORTER: I didn't hear it at all.

16 A Can you repeat your question to make sure I'm answering
17 the right one?

18 Q (By Mr. Bzdok): Sure. So proposed MEC-77, the first two
19 pages has a list of circuits; is that right?

20 A Correct.

21 Q And these circuits are circuits that are proposed to be
22 converted from a lower voltage to 13.2 kV; is that right?

23 A Correct.

24 Q And at the very bottom of that list, on page 2, there is
25 a reference to Discovery Response MNSCDE-15.2a regarding

1 the 2026 and 2027 proposed IRM extension; do you see
2 that?

3 A Correct, yes.

4 COURT REPORTER: Mr. Deol, please keep
5 your voice up, maybe that's why we didn't hear it before.

6 A Oh, I will try to speak louder.

7 COURT REPORTER: Thank you.

8 Q (By Mr. Bzdok): I am interpreting based on the question,
9 the list, and then the statement about 2026 and 2027,
10 that this list is a list of circuits proposed for or
11 planned for voltage upgrade to 13.2 kV in 2025; is that
12 fair?

13 A Correct. However, I don't have an overall schedule here
14 handy, I would have to go look through the exhibits.
15 Some of these may go beyond 2025, but the goal is to
16 convert these in 2025.

17 Q O.K. It's a projected test year, and that's the plan or
18 the projection essentially?

19 A Correct.

20 Q O.K. And for 2026 and 2027, would you agree, high level,
21 that the circuits for conversion have not been identified
22 yet but would be identified in IRM's, IRM plans filed for
23 those years if the extension is approved?

24 A Correct. I'm not the witness for the IRM recovery, but I
25 do believe that we file each year around August or so.

1 Q O.K. There are, subject to check, 31 circuits on this
2 list; would you agree?

3 A Subject to check, yes.

4 Q In the same exhibit, on page 3, we have Response 19.2b,
5 and in that response we asked for each of the circuits
6 that were listed in the first part, which of those will
7 be -- has the Company determined will be overloaded in
8 the next 10 years, correct?

9 A Correct.

10 Q And the Company, after an objection, identified, well,
11 first refer to a Discovery Response 17.5a, correct?

12 A Correct.

13 Q And then identified two circuits as being over the
14 day-to-day rating; is that right?

15 A Correct.

16 Q KENT1334 and HOWRD1247?

17 A Correct.

18 Q And then the Company, so that's 2 out of 31 are over
19 day-to-day rating, correct?

20 A Based on this response, correct.

21 Q And then the Company additionally identified four other
22 circuits as being over DDO, correct?

23 A Correct.

24 Q Is GLEND Glendale?

25 A Sorry, I'm not understanding your question.

1 Q O.K. So those four other circuits are GLEND1974,
2 PINGV0328, RICHM2415, and RICHM2496, correct?

3 A Correct.

4 Q What is DDO?

5 A It's the distribution design order, it's our planning
6 criteria to all the planning engineers.

7 Q So 25 of these circuits that are planned for conversion
8 are neither over their day-to-day rating nor over their
9 DDO; is that right?

10 A Subject to check, I would agree.

11 MR. BZDOK: We will talk about some of
12 these other subparts later, but at this point, just to
13 keep, make sure I do it, I'm going to move to admit
14 proposed Exhibit MEC-77, Discovery Responses 19.2a-f.

15 MS. JOHNSON-BACON: No objection.

16 JUDGE WALLACE: All right. There's no
17 objection to the admission of Exhibit MEC-77, Exhibit
18 MEC-77 is admitted.

19 MR. BZDOK: Thank you.

20 Q (By Mr. Bzdok): Bear with me just a second. O.K. So
21 back to the SharePoint, we're going to spend a lot of
22 time here today with this document, which is proposed
23 Exhibit MEC-81, which is Discovery Response MNSCDE-17.5a.
24 You may need to refresh again. We loaded a bunch of
25 these last night, but not all of them, so we've just

1 loaded the rest this morning.

2 A Will you please repeat which exhibit?

3 Q 81.

4 A I am there.

5 Q O.K. Now, in this question we asked, what percentage, we
6 were looking at your rebuttal, answer, question and
7 answer 16 and 17, and we asked you in reference to that
8 rebuttal, what percentage of 4.8 kV circuits do you
9 believe will exceed their day-to-day rating during the
10 projected test year, correct?

11 A Correct.

12 Q And after a number of objections, the Company provided,
13 referenced an attachment labeled NDA CEII U-21534
14 MNSCDE-17.5a 4.8 kV Circuits, correct?

15 A Correct.

16 Q O.K. And then after discussing the DDO again, the
17 statement is made that, based on the most recent area
18 load analysis, approximately 21.8% of load carrying 4.8
19 kV circuits will exceed their DDO limit in 2025 and 7.6%
20 of load carrying 4.8 kV circuits will exceed their
21 day-to-day rating; is that right?

22 A Correct.

23 MR. BZDOK: O.K. I'm going to move to
24 admit proposed MEC-81 at this time.

25 MS. JOHNSON-BACON: No objection.

1 JUDGE WALLACE: Hearing no objection,
2 Exhibit MEC-81 is admitted.

3 MR. BZDOK: Thank you. We are now at the
4 point, your Honor and Paula, where it would make sense to
5 go into that confidential session so that we can look at
6 that attachment. I don't know if you want to do that now
7 for a few minutes and then take the safety break, or if
8 you want to do that after the safety thing, either way is
9 fine with me.

10 MS. JOHNSON-BACON: I think it might make
11 sense, your Honor, if it's O.K., if we go into the
12 confidential room because in the event anyone has
13 difficulties the way we did on Friday, we'll have time to
14 work it out.

15 JUDGE WALLACE: O.K. All right. Those
16 of you who have, only those of you with the appropriate
17 NDA should leave this and go into the confidential
18 session, and we'll check and confirm that everybody who's
19 supposed to be there is there and -- yeah. So I did send
20 out the invite to everybody who for sure had the CEII
21 NDA, that was forwarded on I think mostly by the Company
22 to other people who also met that criteria. So let's go
23 ahead and reconvene in the confidential room. Again,
24 just for the record, the confidential session will not be
25 recorded, but it will be transcribed. So I'll see you

1 all over there in a minute.

2 (At 9:43 a.m.)

3 - - -

4 (Transcript continues on Page 1283 of the
5 Confidential Record.)

6 - - -

1 (Transcript continues following Page 1304 of the
2 Confidential Record.)

3 - - -

4 (At 10:52 a.m.)

5 JUDGE WALLACE: All right. We're back on
6 the record, the public record in Case No. U-21534.
7 Please continue, Mr. Bzdok.

8 MR. BZDOK: Thank you, your Honor. At
9 this time, I will move to admit what we are going to mark
10 or are marking as proposed Exhibit MEC-121C, which is
11 that NDA CEII 17.5a attachment we were discussing in the
12 confidential session.

13 JUDGE WALLACE: O.K. Is there any
14 objection to the admission of proposed Exhibit MEC-121C?

15 MS. JOHNSON-BACON: No. Thank you.

16 JUDGE WALLACE: O.K. Hearing no
17 objections, that exhibit is admitted, to the confidential
18 record I should say.

19 MS. JOHNSON-BACON: Correct.

20 MR. BZDOK: Thank you.

21 Q (By Mr. Bzdok): Mr. Deol, do you have access to the
22 Distribution Grid Plan, which is Exhibit A-23 Schedule
23 M8?

24 A I do.

25 Q Take a look at that exhibit if you would, and my
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1 reference is exhibit page 90, plan page 89.

2 A O.K. Page 89.

3 Q Yeah.

4 A O.K.

5 Q And let me know when you're there.

6 A I am there.

7 Q O.K. So on this page, there is a discussion of this DDO
8 limit, correct?

9 A Correct.

10 Q It indicates that -- well, first it states that circuits
11 are operated under this DDO limit, in the first sentence
12 of that discussion, and then it gives an example,
13 correct?

14 A Yes.

15 Q And then it makes a statement, "These DDO ratings allow
16 for serving half of an adjacent circuit in the event of
17 an outage while still remaining under the emergency
18 rating for that circuit." Do you see that?

19 A I do.

20 Q What does that mean?

21 A Means for operability, if there is issues or concerns,
22 whether we're doing maintenance or there's an emergent
23 failure, we're looking for the ability to be able to
24 jumper load from one circuit to another circuit to ensure
25 that we limit the outages that would occur in that

1 situation.

2 Q So when we say we're serving half of an adjacent circuit,
3 do we mean half of the adjacent circuit's load, or
4 something else?

5 A Correct, yes, half of the adjacent. We target to be able
6 to have the adjacent circuits to be able to carry half of
7 it, you know, the circuits that it's adjacent to, the
8 ability to be able to carry their load under emergent
9 situations.

10 Q Half their load?

11 A Yes, half of their load.

12 Q In MVA?

13 A In MVA.

14 Q Half of their average load or their peak load or
15 something else?

16 A It would be half of their load that they're serving at
17 that particular time. So you would want, in order for a
18 good circuit design, you'd want to be able to carry the
19 peak load of that, half of the peak load of that adjacent
20 circuit because then you could cover under all
21 situations.

22 Q Is MVA -- so if, what is -- if I have an MVA, if I have a
23 load, if I have a load of 2 MVA, what is half that load,
24 is it 1 or is it something else?

25 A It would be, for the simple scenario, it would be 1. It

1 would be half of the load of that circuit.

2 Q So is it true that having a DDO of 3 in all cases assumes
3 that all adjacent circuits at the time of an outage are
4 serving 6 MVA of load?

5 A Could you repeat your question?

6 Q Yeah. So if the -- so the DDO is 3, correct, for 4.8?

7 A Like what I have explained, right. Maybe we should have
8 added that for the asterisk. It is 3 for, typically for
9 most of the 4.8 system, but there are some circuits,
10 because they're older, that are limited by the cable
11 coming in and out of the breaker positions that their
12 lowered.

13 Q O.K. For purposes of this analysis, the DDA -- the
14 DDO --

15 A Was assumed to be 3 across all circuits for 4.8.

16 Q I used to serve on the DDA, so I'm sometimes going to get
17 mixed up there. The DDO is always 3 for purposes of this
18 analysis for the 4.8 kV circuits, correct?

19 A For, yes, for this analysis, that was the assumption
20 made.

21 Q And you have a qualifier that there may be instances
22 where it would be less than that, depending on, for some
23 old circuits, right?

24 A Right.

25 Q So I will assume always that that qualifier is present

1 just for simplicity sake. I'm trying to understand the
2 relationship of the 3 to what's here in the Distribution
3 Grid Plan. So with that qualifier, a DDO rating of 3
4 means, is an assumption that serving half, that serving
5 half of an adjacent circuit's load is serving 3 MVA,
6 correct?

7 A No. I would characterize that as that's the criteria
8 that you put out there, it doesn't necessarily mean that
9 the other circuits are serving 3, it could be more or it
10 could be less, right, that was the criteria that was
11 established.

12 Q Sure. And just to clarify on the record, so 3 is half of
13 6, correct?

14 A Yes.

15 Q So as a design criteria, this is a design criteria of the
16 DDO being able to serve half of an adjacent circuit
17 that's carrying 6 MVA; is that fair?

18 A No, that's not fair --

19 Q O.K.

20 A -- because --

21 Q Go ahead, explain.

22 A Because the circuit, what it can carry is defined by its
23 elements, right. So the cable, the conductor will define
24 the max amount of current that circuit can carry. You
25 take that, multiply that by the source, whether it's 4.8

1 or 13.2, you would get the ability of what is the load
2 that circuit can carry.

3 Q O.K. In lay terms -- and I apologize for my primitive
4 understanding of this stuff -- is it fair to say that a
5 DDO of 3 is essentially the capacity to carry 3 MVA from
6 an adjacent circuit?

7 A No.

8 Q O.K. How would you characterize that?

9 A I disagree with that statement. The DDO of 3 is to
10 basically state that we do not want the load of that
11 particular circuit to go beyond 3 MVA. As we load -- I
12 mean it's basically as there's growth, there's customers
13 coming on, you want to have that ability, operability to
14 pick up adjacent circuit load that you wouldn't want to
15 go beyond 30. It doesn't necessarily mean that the
16 circuit has the ability to carry 6 MVA.

17 Q Let me try to -- I want to follow up on this a little bit
18 just to make sure that I understand it. For a circuit
19 that meets this criteria, that has a DDO, for a circuit
20 that meets the design criteria embodied by the DDO of a
21 limit of 3, does that mean that circuit can carry its
22 peak load plus up to 3 MVA from an adjacent circuit in an
23 outage?

24 A No, that's not correct.

25 Q What does it mean?

1 A It means that for a 4.8 kV circuit, as we're adding load,
2 because you want to make sure you limit it to 3 MVA,
3 that's all that means. You can't make an assumption of
4 what it can carry in emergency situations or not.

5 Q O.K. What I'm trying to understand is what, then, does
6 it mean that a DDO rating of 3 allows for serving half of
7 an adjacent circuit in the event of an outage while
8 remaining under the emergency rating of that circuit? I
9 wonder if maybe you could give me like an example
10 calculation of that, how would that math work for a 4.8
11 kV circuit and a DDO of 3?

12 A I mean I think for page 89 in the grid plan, it's a
13 general statement of stating half, and as you go circuit
14 by circuit, you would have to analyze those situations
15 because we're running realtime 24/7, the people are,
16 there are people that are monitoring the system, they
17 have their guidelines for each circuit, and they can make
18 the decisions for when we can and when we can't add load
19 and how much load or how much of the adjacent circuit
20 that we can pick up. This here is a general guideline
21 stating that's what we target for necessarily is not true
22 what we have out in the field, especially for the 4.8
23 system which has been in service for a very long time.

24 Q As a design criteria, we're targeting for the ability to
25 pick up up to 3 MVA from an adjacent circuit; is that

1 fair?

2 A No, that's not fair.

3 Q O.K. Tell me, correct me, explain why I'm wrong.

4 A O.K. So if we have a circuit that say it's got 4 MVA on
5 there --

6 Q Yep.

7 A -- right, so we want to limit it to 3, right, for -- we
8 don't want to go beyond the 3 for a day-to-day rating --

9 Q O.K.

10 A -- so it gives us the capacity of 1 MVA, so in an
11 emergency, that particular circuit could pick up 1 MVA of
12 adjacent circuit load.

13 Q O.K.

14 A It might not be half, it might be quarter, it could be
15 the whole circuit, I don't know what's on that adjacent
16 circuit, but it's capacity reserved for those emergent
17 situations to be able to support so we don't have to
18 outage customers unnecessarily.

19 Q Thank you. So the, so the lightbulb came on for me when
20 you offered me that explanation, and let me make sure
21 that I understand it. At a DDO of 3, the extra capacity
22 that a circuit that meets that design criteria would have
23 to pick up an adjacent circuit would be its emergency
24 rating minus 3?

25 A Correct.

1 Q And its emergency rating is higher than its daily rating;
2 is that right?

3 A Correct.

4 Q By how much?

5 A It would depend on each circuit.

6 Q Is there a one-size-fits-all quality to this DDO of 3 in
7 the sense that each circuit has a different emergency
8 rating and so we don't really -- do you understand what
9 I'm saying?

10 A Each circuit is unique, it has unique capabilities, it
11 has unique day-to-day ratings, it has unique emergency
12 ratings.

13 Q So by uniformly applying a DDO of 3 as a design criteria,
14 each circuit will have -- will be sort of -- will have a
15 variable amount of spare capacity it can pick up, spare
16 load it can pick up in an outage?

17 A That was -- that was a criteria that was established for
18 the 4.8 system, but recognize we're not building anymore
19 4.8 systems, we haven't built a 4.8 circuit since the
20 early 1960s, right. Some of these circuits have been
21 serviced since, you know, 1910, 1920 coming across. So
22 this was a guide to make sure that we don't continue to
23 add load to those circuits that have been in service for
24 a particularly long time, and also to have the
25 operability so those situations, when they occur, whether

1 it's maintenance, whether it's emergent situations, that
2 you have some spare capacity to be able to pick up
3 adjacent circuit load.

4 Q And it was provided to us as the dataset that indicates
5 which 4.8 circuits are overloaded and which are not,
6 right?

7 A It was provided in the file that we sent you, correct.

8 Q O.K. In the Distribution Grid Plan, on the page we were
9 looking at, page 89 of the plan and page 90 of the
10 exhibit, it goes on to say that: The DDO limit is
11 comparable to the Rural Utilities Service Standards,
12 which are issued and maintained by the United States
13 Department of Agriculture, or USDA, which require system
14 planning to account for planned and emergency load
15 shifting. Do you see that?

16 A I do see that.

17 Q O.K. To your knowledge, this explanation about the DDO
18 and the rationale and the reference to the USDA document,
19 none of that existed in the prior version of the
20 Distribution Grid Plan, the 2020 plan; is that right?

21 A I would have to take a look to -- I don't have the plan
22 here with me handy.

23 Q O.K.

24 A I just have this current one.

25 Q O.K. In the SharePoint there's a proposed Exhibit
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1 MEC-104. Would you open that, please. It's identified
2 as source USDA Bulletin 1724D-101A. And let me know when
3 you're there.

4 A I'm there.

5 Q Is this the document that's referred to as, that the DDO
6 limit is comparable to the Rural Utilities Service
7 Standards from the USDA?

8 A I don't know, I would have to confer with the author of
9 this document here to see what, what they were referring
10 to. I don't have any references to be able to tell you
11 if it's this one or not.

12 Q When you say the author of this document, for the record,
13 for clarification, you're referring to the author of the
14 Distribution Grid Plan, not the author of the USDA
15 document?

16 A Correct, yes, the author of the Distribution Grid Plan.

17 Q The Distribution Grid Plan goes on to state, "These are
18 the minimum standards required for Rural Co-operatives to
19 receive USDA financial assistance for projects and
20 provide for ensuring capacity for switching as a baseline
21 standard," right?

22 A Yes, it does say that.

23 Q O.K. Do you recall you and I discussing this document
24 last year in 21297?

25 A I do recollect we looked at it.

1 Q Scroll down to page 8 of the document under No. 1,
2 Purpose. And let me know when you're there.

3 A O.K. I am there.

4 Q O.K. So take a look at Purpose, the paragraph under
5 Purpose and the paragraph under, the first paragraph
6 under No. 2, The Long-Range Planning Process. And my
7 question is whether the statements in these paragraphs
8 are consistent with the statement in the Distribution
9 Plan that these are the minimum standards required for
10 Rural Co-ops to receive USDA financial assistance for
11 projects?

12 A Can you repeat your question again, please?

13 Q Yeah. So my question was, is the paragraph under No. 1
14 Purpose and the paragraph, the first paragraph under No.
15 2 The Long-Range Planning Process, consistent with the
16 statement in the Distribution Grid Plan that "These are
17 the minimum standards required for Rural Co-operatives to
18 receive USDA financial assistance for projects?"

19 MS. JOHNSON-BACON: Are you asking his
20 opinion, Chris?

21 MR. BZDOK: Yeah. I'm asking if the --
22 yes.

23 A If I read under Purpose, the second line, it says: It
24 addresses the minimum requirements and responsibilities
25 of system owners, engineers and consultants, and it

1 identifies key engineering principles and methods for
2 reaching sound long-range economic decisions. But like I
3 said, I would have to confer with the author of the DGP
4 to see what the intent was.

5 Q (By Mr. Bzdok): Are you aware of any other Rural
6 Utilities Service Standards issued and maintained by the
7 USDA that the Distribution Grid Plan could be referring
8 to other than these?

9 A I don't know, I would have to go look and verify.

10 Q You're not aware of any?

11 A I am not aware of any.

12 Q Take a look at page 15 of this document, and let me know
13 you're there. I'm looking at Transformer Criteria, Item
14 B.

15 A O.K., I'm there.

16 Q There's a statement in the second paragraph, "Several
17 factors should be considered in establishing criteria for
18 sizing transformers for substations to ensure that
19 equipment remains in service over its useful life,
20 including the initial load and growth rate at the
21 substation location, potential load shifts due to new
22 substations and load shifts during emergency situations."

23 Do you see that?

24 A I do.

25 Q Is that consistent with the statement in the DGP that

1 USDA standards require system planning to account for
2 planned and emergency load shifting?

3 MS. JOHNSON-BACON: Again, you're asking
4 for the witness's opinion?

5 MR. BZDOK: Yep.

6 MS. JOHNSON-BACON: Thank you.

7 A Can you point me to page 89 that you're referring to,
8 please?

9 Q (By Mr. Bzdok): Page 89 in the Distribution Grid Plan.

10 A O.K. Which segment of that page, or which line?

11 Q Let me pull it up, O.K. I have texts excerpted here, but
12 I don't have the document sitting in front of me, so give
13 me a second. So I'm looking at A-23 Schedule M8, page 90
14 of the exhibit, page 89 of the Distribution Grid Plan.

15 A O.K.

16 Q At the top of the page there after a line and a half,
17 there is a bullet point.

18 A Uh-huh.

19 Q And then in that bullet point, about halfway down the
20 bullet point, there's a sentence, "The DDO limit is
21 comparable to the Rural Utilities Service Standards,
22 which are issued and maintained by the United States
23 Department of Agriculture (USDA), which require system
24 planning to account for planned and emergency load
25 shifting." Do you see that?

1 A I do.

2 Q And then my question was whether that is consistent with
3 the statement on page 15 of proposed Exhibit MEC-104,
4 this USDA Rural Utilities Service Standard document?

5 A Like I said, I would have to confer with the author of
6 the DGP and the intent for coming here, for one, what
7 USDA document we're looking at, and then what their
8 intent was in writing versus if this was the document
9 that they used as a reference.

10 Q Bear with me a second. Where would the Distribution Grid
11 Plan get information on distribution design orders if not
12 from your team?

13 A No, they would -- the DDOs are the responsibilities of
14 the engineering team; it's the other aspects of this
15 statement that I would need to confer with.

16 Q Do you recall in our discussion of this document last
17 year, proposed MEC-104 --

18 A I remember --

19 Q Go ahead.

20 A I remember we discussed it, but I don't recollect what
21 was the conversation when we discussed it last time.

22 MS. JOHNSON-BACON: Please let Mr. Bzdok
23 finish his question before you answer. Thanks.

24 Q (By Mr. Bzdok): There's a proposed Exhibit MEC-119 in
25 the SharePoint. Would you pull that up. And when you

1 have pulled it up, I'll ask you to go to page 3 --
2 transcript page 328, and I'll give you an exhibit page in
3 a second.

4 A Sorry, what was the page that you wanted me to go to?

5 Q It's transcript page 328, which is going to be Exhibit
6 Page 149. And actually, we'll start on page, transcript
7 page 327, exhibit page 148. Starting on line 17, can you
8 see that we were looking at your rebuttal testimony from
9 that case, 21297?

10 A Sorry, I'm not there yet.

11 Q Oh, sorry.

12 A O.K., I am there.

13 Q On line 17, can you see we started looking at page 7 of
14 your rebuttal?

15 A Yes, I do see that.

16 Q And then I quoted from your rebuttal starting at line 22,
17 "While there is no universally adopted set of planning
18 criteria across all utilities, one example of a planning
19 standard is the 2017 - USDA Rural Utilities Service
20 Electric System Long-Range Planning, RUS Bulletin.
21 1724D-101A Section 4.b on transformer criteria." Do you
22 see that?

23 A I do see that.

24 Q And that's the section we were just looking at a minute
25 ago in MEC-104; is that right?

1 A Subject to check, yes.

2 Q And then in an answer that begins on, well, there's a
3 question on line 16 of Page 149 where I asked you when
4 you obtained that document; do you see that?

5 A I do see that.

6 Q And you said while you were doing research for the
7 rebuttal testimony in that case; is that right?

8 A That's what I said at that time.

9 Q And then I asked you to clarify that that's not a
10 document DTE had been relying on in system planning, but
11 rather one that you found in doing research for rebuttal;
12 do you see that?

13 A Yes, I do see that.

14 Q And then on the next page, 329 of the transcript, 150 of
15 the exhibit, you said: The question we had gotten, I
16 believe, or we were trying to look to see if there was a
17 standard. Do you see that?

18 A Could you share the line you're looking at?

19 Q Yeah. So 329, page 150 of the exhibit, line 3: The
20 question we had gotten, I believe, or we were trying to
21 look to see if there was a standard.

22 A Yeah, I see that line.

23 Q And then you said: We didn't find the standard, but
24 there is a reference to this in there, meaning the USDA
25 document, right?

1 A I would have to read through the whole thing to get the
2 total gist of what we were talking about.

3 Q Does this refresh your memory that the gist of what we
4 were talking about is whether the Company had an industry
5 standard to cite for single-contingency planning in
6 setting substation ratings, and the Company did not have
7 an industry standard but was able to find this USDA Rural
8 Co-op document for borrowers; does that ring a bell?

9 A It comes back, yes, we were talking about N-1
10 contingencies, yes.

11 MR. BZDOK: Your Honor, I'm going to move
12 to admit proposed Exhibit MEC-104, the USDA Bulletin.

13 MS. JOHNSON-BACON: No objection.

14 JUDGE WALLACE: Absent any objection,
15 Exhibit MEC-104 is admitted.

16 MR. BZDOK: Thank you. Your Honor, may
17 we go off the record for a moment?

18 JUDGE WALLACE: Yes. Off the record.

19 (At 11:32 a.m., brief off-record discussion.)

20 JUDGE WALLACE: Please continue,
21 Mr. Bzdok. We're back on the record. Please continue.

22 MR. BZDOK: Thank you.

23 Q (By Mr. Bzdok): Page 8 of your rebuttal -- I'm going to
24 try to streamline a few of these things. Page 8 of your
25 rebuttal talks about the reliability of 4.8 kV circuits

1 versus 13.2 kV circuits, I'm looking at question and
2 answer 13.

3 A O.K., I'm there.

4 Q In the SharePoint, there's an Exhibit MEC-78, proposed
5 MEC-78, which is Discovery Responses MNSCDE-17.1 and
6 13.11. Do you see those?

7 A I'm just getting to 78. Yes, I do see that.

8 Q So the first one is a question about that rebuttal
9 testimony, which refers to Discovery Response 13.11, and
10 the second page is 13.11, right?

11 A Correct.

12 MR. BZDOK: I'll move to admit proposed
13 MEC-78.

14 MS. JOHNSON-BACON: No objection.

15 JUDGE WALLACE: O.K. Hearing no
16 objection, MEC-78, Exhibit MEC-78 is admitted.

17 MR. BZDOK: I'm going to go ahead also,
18 then, and move to admit -- we can ask questions about
19 them, Paula, if you want, but just to try to shortcut
20 some things -- MEC-79, which is Discovery Response
21 MNSCDE-17.6 and an Attachment 2018 to 2022 All Weather
22 SAIDI, as well as MEC-80, which is MNSCDE-17.4 and 15.34e
23 and an attachment to 15.34e.

24 JUDGE WALLACE: Is there any objection to
25 admitting Exhibits MEC-79 or MEC-80?

1 Hearing none, those exhibits are
2 admitted.

3 MR. BZDOK: Thank you.

4 Q (By Mr. Bzdok): Let's take a look at your rebuttal now
5 on question and answer 17.

6 A Yes, O.K.

7 Q So on page 11 of your rebuttal, question and answer 17,
8 you're responding to witness for the Attorney General,
9 MEC, and NRDC Dennis Stephens on the issue of circuit
10 loading in the 4.8 kV circuits, right?

11 A Can you please let me know what page that was again.

12 Q 11.

13 A I wasn't looking. Page 11?

14 Q Yep. Q and A17.

15 A Sorry, I'm there.

16 Q So I'm just orienting us right now. Here you're
17 responding to Witness Stephens regarding circuit loading
18 in the context of and its relationship to the 4.8 kV
19 circuit conversions projects, correct?

20 A Yeah, it's responding to Witness Stephens' statements
21 about capacity.

22 Q In the SharePoint -- O.K. So sorry. So in that, in your
23 answer, you say, you make a statement starting on line
24 18, you say: As stated in the Company's 2023 DGP filing,
25 the Company prioritizes near-term conversions -- nope,

1 sorry, I had the wrong line. Strike that.

2 You state, starting on line 13,

3 "Additionally, the Company must maintain a capacity
4 margin for operating the system during maintenance and
5 trouble events. This includes not just day-to-day
6 circuit capacity, but also the source substation
7 capacity, and circuit emergency ratings, which all impact
8 the ability to operate the system during planned or
9 unplanned outage events as well as the ability to support
10 load growth." Do you see that?

11 A Yes, I do see that.

12 Q And then you have a footnote 17 in the middle of that
13 sentence where you make a statement, "20% of the
14 Company's 4.8 kV substations operate over firm rating",
15 correct?

16 A Correct.

17 Q In the SharePoint, there is a discovery response, or a
18 request and response about that, it's proposed Exhibit
19 MEC-120, MNSCDE-17.5c. Let me know when you're there.

20 A I'm there.

21 Q We asked you for the source of that claim, that 20% of
22 the 4.8 kV subs operate over firm rating, right?

23 A Yes, you did.

24 Q And the answer is by reference to the Distribution Grid
25 Plan, correct, A-23 Schedule M8?

1 A Yes.

2 Q Do you still have that plan available, we were looking at
3 it a minute ago?

4 A Yes, I do.

5 Q Pull that up, if you would. I want to walk through the
6 references in the discovery response for the basis of the
7 assertion of 20% of the subs operating over firm rating.
8 So the place to start will be, or the Discovery Response
9 is page 9 of the exhibit, which is page 8 of the plan.

10 A So you want me to go to page 8 of the DGP?

11 Q Yeah.

12 A O.K. I'm on page 8.

13 Q So there's a reference in the discovery response to that
14 Exhibit 1.2.1 at the bottom; do you see that?

15 A I do see that.

16 Q And the number for, of 244 general purpose 4.8 kV
17 substations is there in the table, right?

18 A Correct.

19 Q And then the discovery response also cites page 122 of
20 the exhibit, which is 121 of the plan.

21 A Yes.

22 Q And the reference in that discovery response is to
23 Exhibit 9.3.6.2 - Conversion Projects, et cetera, right?

24 A Yes.

25 Q Conversion Projects, I should say, to Address 25 4.8 kV

1 Substations with Highest Loading Constraints, correct?

2 A Correct.

3 Q So tell me if I'm wrong here, but the table seems to
4 refer to 25 substations with loading constraints and then
5 another 24 substations adjacent to them; would you agree?

6 A Yes, I would, but I also would want to point out, if you
7 go look on page 19, this was a plan 2029 and beyond, so
8 that table defines that situation.

9 Q So I just want to make sure I understood what you said.
10 Are you saying if you look at page 19 of the Distribution
11 Grid Plan?

12 A Page 19.

13 Q In your answer just now, you said page 19, I wanted to
14 make sure I had that right.

15 A If you go look at page 119, 119.

16 Q So I think what you said was if you look at page 119, the
17 section is talking about a conversion plan for 2029 and
18 beyond; is that what you said?

19 A Correct.

20 Q So that means in reference to the tables that this is
21 identifying, 25 substations that need to be dealt with in
22 a time horizon of 2029 or beyond; is that right?

23 A Yes, the table that you referred to on page 121 is future
24 looking.

25 Q And for those substations that need to be addressed in

1 that future time horizon of 2029 or beyond, 25 of those
2 have, are described as having loading constraints and the
3 other 24 are described as being adjacent to them,
4 correct?

5 A For the future, yes.

6 Q So this information in the Distribution Grid Plan really
7 provides no basis for a claim of, that 20% of the
8 Company's 4.8 kV subs currently operate over firm rating;
9 would you agree?

10 A Correct. I was -- I guess the answer provided was future
11 looking. But I have a reference that, if you would like,
12 that would answer the question as maybe was
13 misinterpreted from our side when we provided that
14 answer. I do have a reference.

15 Q You're welcome to pursue that on redirect if you and your
16 counsel choose to. My question for you was about the
17 statement in the rebuttal and then the explanation of the
18 basis for it in 17.5c.

19 MR. BZDOK: I will move at this time for
20 the admission of Exhibit MEC-120.

21 MS. JOHNSON-BACON: No objection.

22 JUDGE WALLACE: Hearing no objection,
23 Exhibit MEC-120 is admitted.

24 Q (By Mr. Bzdok): Let's talk about subtransmission
25 redesign and rebuild.

1 A O.K.

2 Q General high level, what is this program about, for
3 context?

4 A This program is about the areas of the subtransmission
5 system that need -- that has issues; it could be voltage
6 violations, it could be -- well, simplify -- parts of the
7 subtrans system that has violations or planning criteria
8 which has reliability issues and concerns where we need
9 to update that part of the system.

10 Q And what's the subtrans system, just for context, high
11 level.

12 A High level, subtrans is the, I guess the backbone of the
13 distribution system. So the distribution system or a
14 distribution substation takes voltage at a higher level,
15 converts it to either 4.8 kV, 8.3 kV, or 13.2 kV, and
16 distributes it to the customers, whereas the subtrans
17 system from the distribution or a generating source is
18 bringing the power or the source to each of the
19 distribution substations.

20 MR. BZDOK: Your Honor, to streamline,
21 I'm going to offer a few of these discovery exhibits
22 without questions, they're going to be MEC-82, 83, 84,
23 they're all responses from Mr. Deol. 82 is MNSCDE-17.6,
24 referring to his rebuttal at page 25, some lines that are
25 stated; 83 is MNSCDE-19.5a and b, also referring to

1 Mr. Deol's rebuttal at page 24; and MEC-84 is
2 MNSCDE-19.6, asking some questions about his rebuttal at
3 page 25.

4 JUDGE WALLACE: Is there any objection to
5 the admission of Exhibit MEC-82, MEC-83, or MEC-84?

6 Hearing no objections, those exhibits are
7 admitted.

8 MR. BZDOK: Thank you.

9 Q (By Mr. Bzdok): Mr. Deol, please take a look at your
10 rebuttal testimony on page 26.

11 A O.K., I am there.

12 Q O.K. So generally in answer 34 --

13 A Yes.

14 Q -- you're discussing an annual process of updating
15 loading information for the subtrans system; is that
16 right?

17 A Correct.

18 Q And you indicate, starting at line 17, that: The
19 analysis performed revealed that one-third of the
20 circuits on the subtransmission system has a thermal
21 and/or a voltage planning criteria violation, correct?

22 A This was the, one of the updates that we made this
23 morning.

24 Q Can you repeat that update for me?

25 A That, we added, so that line 17 should add the analysis

1 performed revealed that one-third of the circuit miles on
2 the subtransmission system has -- go on.

3 Q So it was a change of circuits to circuit miles?

4 A Correct.

5 Q O.K. Thank you for catching me there. And then at line
6 19 you say that a sample of that data was provided in the
7 discovery response to us, MNSCDE-5.15a(S1); is that
8 right?

9 A Correct.

10 Q And then you also included it in Exhibits A-50 Schedule
11 001 and 002, correct?

12 A Correct.

13 Q And do you have those exhibits available to you?

14 A I do.

15 Q O.K. So 001 is a public exhibit, which is what I tend to
16 call the narrative response to that discovery request
17 from us; is that right?

18 A I would characterize it that was the response we provided
19 for that question itself.

20 Q O.K. There's a response consisting of text, which is
21 001, a public document, and there is a response
22 consisting of data, which is an attachment to 5.5a, which
23 is Confidential CEII A-50 002, fair?

24 A Correct.

25 Q O.K. And in the words part of the response, 001 -- well,
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1 the question was that what we asked you to do under
2 subpart (a) was to: Provide any and all load forecasts,
3 capacity ratings, and other information which shows that
4 the Company's subtransmission capacity planning criteria
5 would be overloaded by December 31, 2028, correct?

6 A Correct, that was the question.

7 Q And then there were objections and then there was an
8 answer to see that confidential attachment, which you've
9 submitted as Rebuttal Exhibit 002, correct?

10 A Correct.

11 Q O.K. What I would like to do, if it's possible, is to
12 talk about this exhibit in public session without
13 identifying any numbers specific to any circuit.

14 A O.K.

15 Q If I do ask you a question that you feel is going to
16 require you to provide information that's confidential or
17 CEII, you know, just stop and, you know, we'll deal it
18 off the record or in confidential, O.K.?

19 A O.K.

20 Q O.K. So I'm first going to ask you about the -- so I'm
21 looking at A-50 Schedule 002.

22 A O.K.

23 Q And I'm going to ask you, as I do typically, about the
24 column headings first and what they mean without
25 reference to particular numbers or circuits.

1 A Uh-huh.

2 Q So what I see in the -- and so I'm interested in, at this
3 point, pages 1 and 2 talk about the thermal analysis,
4 right?

5 A Correct.

6 Q And the thermal analysis is comprised of analyses
7 completed in 2020 for the forecast year of 2022 and
8 analyses completed in 2024 for the forecast year of 2026,
9 fair?

10 A I guess I would answer it as we had stated, that these
11 are sample data sets.

12 Q O.K.

13 A So --

14 Q O.K. We asked for all forecasts, and you gave us a
15 sample under objection, right?

16 A The question asked if we had data for 2028, and we
17 objected basically stating that we didn't have the data
18 or we performed that analysis. As a sense of
19 transparency, we provided two data sets to say that this,
20 so we're basically looking for a detail of our analysis
21 of this for, with valid data, thus the data that we
22 looked at previously in the CEII portion, it's taking
23 that data and we're projecting two years out. So this is
24 saying that based on that system, we're looking two years
25 out, and we gave a sample set for 2020 and then some data

1 from 2024.

2 Q O.K. I appreciate that clarification. Take a look at
3 the SharePoint, proposed Exhibit MEC-85, which is
4 Discovery Response MNSCDE-17.8, and let me know when
5 you're there.

6 A Sorry, could you please repeat the number again, the
7 exhibit number?

8 Q Yeah. MEC-85, which is Discovery Response MNSCDE 17.8.

9 A O.K., I'm there.

10 Q O.K. So here we were looking at page 27 of your rebuttal
11 where you're discussing thermal violations in the
12 subtransmission planning, the sub -- of thermal
13 violations for subtransmission planning criteria, and we
14 asked you to identify all instances of subtransmission
15 equipment experiencing loadings above 100% of their
16 normal rating, and you referred us to this same two pages
17 of data, correct, in Schedule 002?

18 A Yes, based on our response, yes.

19 Q O.K. Back to that data, pages 1 and 2, after the column
20 for the year analysis is completed and the forecast year,
21 there is the identifier for the tie or trunk; is that
22 right?

23 A Yes, that's the circuit, yes.

24 Q Would it be correct to say a tie line or a trunk line or
25 a tie circuit or a trunk circuit, what would be my

1 appropriate terminology?

2 A It would be just tie and trunk.

3 Q O.K. The next column is normal rating, N-0 in MVA,
4 correct?

5 A Correct.

6 Q And you indicated in another discovery response -- I'm
7 just going to ask you because I know the answer but we'll
8 put it on the record -- this is the circuit's normal
9 rating under system normal conditions, no contingency
10 during peak loading; is that right?

11 A Correct.

12 Q And then emergency rating N-1 MVA -- well, let me back
13 up. Let me take them functionally.

14 So two columns over is normal flow, N-0
15 MVA, correct?

16 A Correct.

17 Q And that's defined as the load flow on the circuit in MVA
18 under system normal conditions no contingency during peak
19 loading season; is that right?

20 A Correct.

21 Q So is that peak demand -- I'm sorry -- a peak loading, or
22 is that something else, normal flow?

23 A That's under system -- under normal conditions, that's
24 what we load the MVA rating that that circuit can see or
25 will see.

1 Q Is it -- I'm sorry to be dense. Is it its peak flow or
2 is it something else that it will see; is it the peak
3 flow it will see or is it something else?

4 A It's under system peak conditions, what that circuit will
5 see under normal configuration.

6 Q Thank you. And then emergency rating N-1 MVA is what?

7 A That would be still that system peak if we had an, under
8 N-1 scenario, that's what the MVA that that circuit would
9 see.

10 Q N-1 scenario is also called single contingency?

11 A Correct.

12 Q And --

13 A Sorry. Let me go back, just quick. Let me correct
14 myself.

15 Q O.K.

16 A So the normal rating, zero MVA, that would be the design
17 capacity for that circuit that it could handle, and then
18 the next column would be the emergency rating for that
19 circuit.

20 Q O.K. So in lay terms, what does it mean that it's the --
21 let me make sure I have it straight because I wrote down
22 something different than maybe I think it is. The
23 emergency rating N-1 MVA is the design capacity for a
24 single contingency scenario?

25 A For that particular circuit, that would be under

1 emergency situations, that circuit could carry that load.

2 Q O.K. And emergency flow N-1 MVA is the load that circuit
3 would see in a single contingency scenario?

4 A Correct.

5 Q And that means if some other element of the system was
6 out and that circuit needed to take load from the element
7 that was out, is that what the contingent, single
8 contingency N-1 scenario means?

9 A Correct.

10 Q O.K. And then loading, percent loading N-0 violation
11 means, that's a comparison of the normal rating to the
12 normal flow, which is the peak flow; is that right?

13 A Yes. It's called -- I don't have the columns labeled, so
14 looking at the data, it's the third column divided by the
15 first column.

16 Q And so a number over 100% means that the normal design
17 capacity is greater than the load under system peak
18 conditions?

19 A So that would be under system peak conditions, that line
20 would see if it's, what percentage it would see over its
21 ratings.

22 Q And a blank in that percent loading N-0 violation means
23 the number is less than 100%?

24 A Correct.

25 Q And a percent loading N-1 violation in the far right

1 column is more or less the same but for, but based on a
2 comparison of emergency rating to emergency flow during
3 system peak conditions?

4 A Correct. I have to verify what the limit is, it's less
5 than 100%.

6 Q O.K.

7 A Yeah. If you go look at my rebuttal testimony on page
8 28 --

9 Q Yep.

10 A -- that defines what the N-1 contingency criteria is.

11 Q So there I think you're looking at lines 5 through 11?

12 A Or actually if you look at page 27, line 24, 24 and 25,
13 then continuing on page 28, line 1 through 3.

14 Q O.K. So is the -- so that the values on 002 under
15 emergency rating N-1 MVA, are those values the emergency
16 rating for the circuit or are they 90% of the emergency
17 rating for the circuit?

18 A That value is derived by taking the fourth column and
19 dividing it by the second column.

20 Q Sorry. I was clarifying something and I think -- I
21 understand what you just answered, but it was not what I
22 was asking. So I'm looking at the fourth column over,
23 emergency rating N-1 MVA.

24 A O.K.

25 Q And I was trying to make sure I understood your answer

1 about 90%.

2 A O.K.

3 Q And so my question is, is the emergency rating N-1, is
4 that the emergency rating of the circuit, or is that 90%
5 of the emergency rating of the circuit, based on what you
6 were telling me about 90%?

7 A I guess I'm confused on which column are you asking me
8 the question of?

9 Q I see. Because there's, it's actually column 5. Yep.
10 So I'm asking about the fifth column over, emergency
11 rating N-1 MVA, and I'm just asking, is that -- are those
12 values the emergency rating for the circuit or 90% of the
13 emergency rating for the circuit?

14 A Oh, I'm still confused on what you're asking me.

15 Q O.K. So in the testimony you were just pointing us to,
16 bottom of page 27, top of page 28, you indicated more or
17 less that when a single contingency event occurs for a
18 limited period of time, the subtransmission equipment can
19 be loaded to 90% of its emergency rating, correct?

20 A Correct.

21 Q And so I'm trying to interpret on 002 whether the values
22 under the column titled emergency rating N-1 --

23 A Right.

24 Q -- are those the emergency, 100% of the emergency rating
25 of the circuit or 90% of the emergency rating of the

1 circuit?

2 A Got it. Thank you for the clarity, I get it now. So the
3 column that says emergency rating N-1 MVA, that is the
4 100% emergency rating.

5 Q O.K. And then loading, percent loading N-1 violation I
6 think you mentioned was column, a column titled emergency
7 flow N-1 divided by the column titled emergency rating
8 N-1, correct?

9 A Correct.

10 Q And so what you're saying is any time there's a number,
11 any of the numbers under percent loading N-1 violation
12 are 90% or above, that's considered a violation for
13 design purposes?

14 A Correct.

15 Q O.K. Got it. In your rebuttal, you, on page 27 line
16 12 -- sorry -- line 15, you give an example of a
17 subtransmission trunk line TRK4217. Do you see that?

18 A Yes.

19 Q And you indicate it has a normal rating of 19 MVA, yet it
20 currently serves 21.8 MVA of load under normal operating
21 conditions, meaning this table is loaded to 115% of its
22 normal rating, right?

23 A Correct.

24 Q If you look at Schedule 002 filed with your rebuttal,
25 two-thirds or so of the way down -- no -- maybe a little

1 more than half the way down I should say, in the third
2 column, you'll find a reference to TRK4217?

3 A Correct.

4 Q And that indicates a normal rating of 19 MVA?

5 A Correct.

6 Q Consistent with your rebuttal testimony, right?

7 A Uh-huh.

8 Q (Question removed due to confidential nature.)

9 MS. JOHNSON-BACON: Chris, I just had my
10 team light up.

11 MR. BZDOK: I apologize. You know, it's
12 because he gave numbers in his public testimony that I --
13 I apologize. Could we go off the record?

14 JUDGE WALLACE: Off the record.

15 (At 12:15 p.m., off-record discussion.)

16 Q (By Mr. Bzdok): (Pending question being re-stated.) So
17 Mr. Deol, the normal flow in Schedule 002 is different
18 than the number in line 16 of your rebuttal for what
19 TRK4217 currently serves; is that right?

20 A Correct.

21 Q And where your rebuttal indicates that the cable, that
22 cable is loaded to 115% of its normal rating, Exhibit
23 A-50 Schedule 002 does not indicate any percent loading
24 N-0 violation, correct?

25 A So that data is based on 2020, right. That's when the
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1 data was gathered for a projected flow in 2022. I
2 would --

3 Q So I'm happy to -- go ahead.

4 A I would have to go verify the, where the loading data is
5 in to determine which year we're referencing for.

6 Q O.K. So just so the transcript is clear, because we're
7 trying to do a public, right, exam on a confidential
8 document, just the math, and I'm -- I understand your
9 explanation -- but just the math, would you agree that,
10 or just as to the data, Schedule 002 does not indicate
11 any percent loading N-0 violation for TRK4217?

12 A So based on that schedule for that particular circuit,
13 for the analysis done in 2020 looking at 2020 loading,
14 that circuit would be 98.9% of its normal flow.

15 Q And there is no percent loading N-0 violation indicated
16 for it in Schedule 002, correct?

17 A If it's below 100% of the planning criteria, that's why
18 it's not listed.

19 Q So you're agreeing with me?

20 A I agree there's no data in that column for that
21 particular circuit.

22 Q O.K. Which the way this data is presented is a finding
23 of no loading violation under normal conditions, right?

24 A Correct.

25 MR. BZDOK: Lori, did you get that
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1 correct?

2 COURT REPORTER: Yes, I did, the very end
3 of it.

4 Q (By Mr. Bzdok): O.K. And in Exhibit MEC-85, where we
5 asked you specifically about your rebuttal testimony
6 about TRK4217, to give us all the loadings above 100% of
7 the normal rating, you referred us only to this Schedule
8 002, pages 1 and 2, correct?

9 A Sorry, can you please ask the question again?

10 Q So when we asked you about this very set of rebuttal
11 testimony, about TRK4217 where you made the claims about
12 loading and being above its normal rating and we asked
13 you for all data for loadings above 100% of normal
14 rating, Schedule 002 is the data you referred us to,
15 right?

16 A Per the answer, correct.

17 MR. BZDOK: I'm going to move to admit
18 proposed Exhibit MEC-85.

19 MS. JOHNSON-BACON: No objection from the
20 Company.

21 JUDGE WALLACE: Hearing no objection,
22 Exhibit MEC-85 is admitted. Mr. Bzdok, please start
23 thinking about a break here in the next few minutes.

24 MR. BZDOK: This is a fine time if you'd
25 like to do it now. Happy to go further or do it now.

1 JUDGE WALLACE: All right. Why don't we
2 go ahead and take a break for lunch. Is 45 minutes O.K.
3 for everybody?

4 MS. MAYABB: I do have a question before
5 we leave as long as all the parties are here. I am
6 recording this for the Commission, this is a public
7 recording. What do I do with the confidential?

8 MR. BZDOK: Same thing they do with those
9 parts of the Nixon tapes.

10 JUDGE WALLACE: I was going to say --

11 MS. MAYABB: I did have the whereabouts
12 to indicate at approximately what time in the recording
13 that the confidential information was provided, but I
14 don't know what to do with the recording.

15 JUDGE WALLACE: Can you check with IT?

16 MS. MAYABB: I will. You know, this
17 isn't public until it gets loaded, but it gets loaded to
18 a public -- I actually don't know where it gets loaded,
19 but I know it's public, so I will look into it, but I
20 just wanted you to be aware that it obviously was
21 recorded.

22 JUDGE WALLACE: All right. I mean the
23 Commission has access to all of the confidential
24 material, so that's not a problem. It's a problem,
25 though, if it becomes, you know, something somebody else

1 wants to view. So yeah, check with IT to see, I think
2 you can probably delete it, or I don't know, record over
3 it with an air horn or something to make it go away.

4 So we are off the record. And it's
5 12:24, so why don't we say 1:15, everybody be back here
6 then.

7 (At 12:24 p.m., the hearing recessed for lunch.)

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Monday, September 9, 2024

At 1:25 p.m.

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(Hearing resumes following the lunch recess.)

JUDGE WALLACE: All right. We're back on the record in U-21534. And so, Mr. Bzdok, please continue your cross-examination.

MR. BZDOK: Thank you, your Honor. First, as a matter of housekeeping, Mr. Deol and I discussed before the break proposed Exhibit MEC-119, which was his complete testimony in 21297, and I'd like to move for the admission of that at this time.

JUDGE WALLACE: Any objection to the admission of Exhibit MEC-119?

Hearing none, that exhibit -- I'm sorry.

MS. JOHNSON-BACON: No, I mean it seems redundant because it was in the record in another proceeding, but I don't have any objection to that.

JUDGE WALLACE: O.K. Belt and suspenders. Hearing no objection, Exhibit MEC-119 is admitted. Mr. Bzdok, did we admit Exhibit MEC-85?

COURT REPORTER: Yes. I have it crossed that we admitted it.

MR. BZDOK: I have it listed, too.

JUDGE WALLACE: O.K. All right. Please
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1 continue, Mr. Bzdok.

2 MR. BZDOK: Thank you.

3 - - -

4 S A T V I R R. D E O L

5 resumed the stand, and having been previously sworn,
6 testified further as follows:

7 CROSS-EXAMINATION (Continuing)

8 BY MR. BZDOK:

9 Q Mr. Deol, I'd like to go back to Exhibit A-12 Schedule
10 B5.4 again, your pages of that.

11 MR. BZDOK: Am I echoing?

12 COURT REPORTER: No.

13 MR. BZDOK: Great. Only in the corners
14 of my mind.

15 A O.K.

16 Q (By Mr. Bzdok): In, so page 14, lines 7 to 19.

17 A O.K. Which lines, please?

18 Q Yeah. So actually it's, so I'm looking at, first I'm
19 looking at lines 7 to 10, and lines 13 to 19 contain
20 Subtransmission Redesign & Rebuild: Tie and Trunk
21 projects; would you agree?

22 A Correct, I agree.

23 Q Of those subtrans tie and trunk projects, other than the
24 TRK4217 that we talked about before the break, the only
25 other one of those I was able to find in the sample of

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1 data provided to us was TRK4266. Do you have any reason
2 to disagree with that, are you aware of any of these
3 other projects which would have been in that data sample?

4 A Just for me to clarify, which data sample are you
5 referring to?

6 Q 002, A-50 Schedule 002.

7 A Subject to check, but also why I wanted to clarify again
8 what I reiterated, that was a sample set.

9 Q And I'll clarify again that when we asked you for all the
10 ratings, you referred us back to that sample set, right?

11 A We provided a sample set.

12 Q High level -- well, without getting into any numbers,
13 TRK4911 -- no, I'll strike that, I'll move on.

14 Table 8 -- no, why don't we do that. So
15 TRK4911 appears on Schedule 002 about two-thirds of the
16 way down the page. Can you find that?

17 A What was the circuit designation? And we are --

18 Q TRK -- oh, you know what, I confused you. I apologize.
19 I am going to ask you about TRK4911, but not yet.
20 TRK4266, which is on your Exhibit A-12 Schedule B5.4,
21 appears on Exhibit A-50 Schedule 002 on the second page,
22 maybe 10 or 11 rows up from the bottom. Do you see that?

23 A I do see that.

24 Q O.K. In your direct -- go ahead.

25 A I also do want to clarify that if I'm looking at Schedule
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1 002, I do see Trunk 2466 kind of midway in the 2020 data.

2 Q Give me a second. Trunk 2466 did you say?

3 A Correct.

4 Q And you say it's midway in the 2020 data?

5 A Correct.

6 Q Give me a second to see if I can find it. What is it
7 above and below, I'm not finding it?

8 A It's below Trunk 4217.

9 Q 4266?

10 A Right.

11 Q O.K. I heard maybe 2466.

12 A That's the circuit that you told me to look at, right,
13 4266?

14 Q Yes. Yes. O.K. Give me a second. O.K. So TRK4266
15 appears, as you indicated, maybe midway through the 2020
16 data on page 1, and then would you agree it also appears
17 in the 2024 data on page 2, maybe 10 or 11 up from the
18 bottom?

19 A Correct.

20 Q Page -- in your direct testimony, you have a Table 8,
21 which is Subtransmission Projects, it starts on page 57
22 of your direct and goes over to 58 and 59 of your direct.
23 Are you able to locate that?

24 A Are you referring to page 58 about six from the bottom?

25 Q Yes.

1 A O.K. O.K.

2 Q And so what you were referring to there was the entry in
3 the Table 8 for Trunk 4266, correct, that's what you were
4 pointing me to?

5 A Yeah, the table on page 58, I was just clarifying we were
6 looking at the same table.

7 Q Yep. So there it indicates one of the drivers is
8 capacity, that Trunk 4266 is loaded to 108% of the
9 equipment's summer emergency rating, violating the
10 subtransmission planning criteria, correct?

11 A Correct.

12 Q And would you agree with me that in Schedule 002, neither
13 the 2022 entry for Trunk 4266 nor the 2026 entry for
14 Trunk 4266 matches that number?

15 A I guess if I go look at that description, I have to go
16 get clarification on the summer emergency rating
17 violation there. I just want to make sure that we were
18 looking at the same for what's on the file based on
19 what's on this datapoint here.

20 Q Is what you're suggesting that maybe the summer emergency
21 rating violation would be something other than the
22 percent loading N-1 violation?

23 A I have to go look and verify the summer emergency loading
24 numbers there.

25 Q O.K.

1 A And I don't have that data with me at the moment.

2 Q Is summer emergency -- so is what you're saying that
3 summer emergency load is something different than single
4 contingency --

5 A I'd have to go --

6 MS. JOHNSON-BACON: Let him finish his
7 question, please.

8 Q (By Mr. Bzdok): Is what you're saying is that they're
9 different, or you don't know if they're different, that
10 was really my question?

11 A I'd have to go and verify that to answer your question.

12 Q You don't know if they're different or not without
13 verifying?

14 A Yeah, without verifying, no.

15 Q O.K. Look at Table 8, still in your direct on page 59.

16 A O.K.

17 Q So here you have a number of subtransmission projects
18 listed that -- so I'm going to tell you, I'm going to
19 make a statement and then I'm going to ask you what I
20 think it means. O.K. So you have a number of projects
21 listed on page 59 in that Table 8 that are not on Exhibit
22 A-12 Schedule B5.4, and if that's -- so my questions are
23 twofold. (1) is, is that correct, and (2) does that mean
24 these are IRM projects? Oop, never mind. I found them.
25 Strike that question.

1 So I found these on, I found these Table
2 8 page 59 projects on Exhibit A-12 Schedule B5.4, page
3 15, lines 66 to -- at least some of them in line 66 to
4 78. Does that seem right?

5 A Yeah. And I see there's additional subtrans projects
6 listed in line 66 through 78 on page 15. I have to
7 cross-reference to check to make sure they're all there
8 through the table.

9 Q O.K. The third from the bottom on Table 8 is Trunk 4911;
10 is that right?

11 A Are we referring to page 59?

12 Q Yep.

13 A Yeah, I see that.

14 Q And under capacity for drivers, Trunk 4911 experienced
15 multiple overloads in a normal and emergency scenario up
16 to 130% of equipment rating, violating the
17 subtransmission planning criteria; do you see that?

18 A Yes, I do see that.

19 Q The only mention I can find of Trunk 4911 in Exhibit A-50
20 Schedule 002 is about two-thirds of the way down the
21 first page, a few lines below the two we were looking at
22 before. Are you able to locate it?

23 A Is that on page 1 or page 2?

24 Q Page 1.

25 A Yeah, I was able to locate it.

1 Q Would you agree with me that the percent loading N-0
2 violation and the percent loading N-1 violation for Trunk
3 4911 in Exhibit A-50 Schedule 002 does not match the 130%
4 number in Table 8?

5 A I need to verify what year the study was conducted to
6 those, for the numbers that were listed here on page 59
7 compared to Schedule 002 that we're looking at that
8 states that it was a study conducted in 2020 using
9 forecasted 2022 loading.

10 Q You agree that the numbers don't match, just for purposes
11 of the public transcript, as to the confidential
12 document?

13 A Not knowing the year when the study was done, I can't
14 tell you one way or the other. I would have to confirm
15 to verify what timeframe this data in the table is
16 compared to the data that was conducted here on the
17 schedule here that I've got definitions of years there, I
18 don't have that on the table.

19 Q So I'm understanding your testimony to be that you would
20 need to take certain steps to explain whether there is a
21 reason why the numbers don't match. But my question is,
22 literally the numbers in the two documents don't match,
23 right?

24 MS. JOHNSON-BACON: I'm going to object.

25 I think that's a mischaracterization of Mr. Deol's

1 testimony. He says he doesn't know what year the table
2 data came from, so he can't tell if they match or if they
3 don't. It could be from a completely different year.

4 JUDGE WALLACE: Seems to me that
5 Mr. Bzdok's question is pretty straight forward, do the
6 numbers match or not, and if they don't, there might be
7 an explanation for that that we may or may not go into.
8 So do the numbers match?

9 MS. JOHNSON-BACON: You can go ahead and
10 answer.

11 A Yes, on the data provided, no, they don't match.

12 MR. BZDOK: Thank you.

13 JUDGE WALLACE: Thank you.

14 Q (By Mr. Bzdok): What are -- what in general are
15 emergency ratings? I think you actually, you told me
16 this earlier today. Do I recall you telling me that
17 emergency ratings are ratings that equipment is designed
18 to carry loads up to for limited periods of time; do I
19 recall that correctly?

20 A I believe I refer back to this, I've looked on a break,
21 we've answered this question describing each of what the
22 table headers are for this page.

23 Q O.K. And --

24 A It's one of the discovery questions.

25 Q Bear with me a sec. 17.7?

1 MS. JOHNSON-BACON: Correct, if that's
2 helpful.

3 Q (By Mr. Bzdok): And I don't -- so it is helpful, because
4 I want to maybe clarify my question a little bit more.
5 So apart from, apart from the columns and in the table,
6 my question is sort of in general, what is an emergency
7 rating?

8 A Let me refer to -- let me look it up. It's in there.

9 Q O.K.

10 A So if you refer to my testimony, page 77 --

11 Q Yep.

12 A -- lines 3 through 23 on that page describe the different
13 types of ratings.

14 Q So it's fair to say that equipment is designed to operate
15 at emergency rating, but only for a short period of time,
16 fair?

17 A That's fair.

18 Q The modeling that was done in OO2 for emergency rating
19 violations during N-1 conditions, did that modeling have
20 any minimum duration for the exceedances?

21 A The way the model works is it's just you're stimulating
22 different configurations of the system to see what would
23 happen; you don't model how long or so on because that
24 depends on each scenario when that does happen in the
25 real system.

1 Q O.K. Are there -- do there exist equipment solutions to
2 thermal violations for some scenarios that do not require
3 a full rebuild?

4 A You would go case by case, it's dependent on the
5 situation; sometimes it's a simpler solution, sometimes
6 it takes more.

7 Q Is adding a transformer bank an example of a solution
8 that may work in some scenarios?

9 A Like I said, I guess it would depend on a scenario, but
10 adding a transformer bank would be more towards voltage
11 violations than thermal.

12 Q Take a look at your rebuttal testimony on page 28.

13 A O.K. I'm looking at it.

14 Q So starting at line 13, question and answer 36, and
15 carrying over to page 29, you have about a page and a
16 half explanation of an example from a component called
17 Trunk 359 that you indicate demonstrates a thermal
18 violation where the Company had to shed load until mobile
19 equipment was deployed, correct?

20 A Correct.

21 Q In discovery, so in proposed Exhibit MEC-86, which is
22 Discovery Response MNSCDE-17.9 --

23 A Sorry, can you please repeat the exhibit number?

24 Q 86.

25 A O.K.

1 Q And let me know when you're there.

2 A I'm there.

3 Q In this question we asked you to provide all, to identify
4 all the subtrans redesign and rebuild projects that
5 address equipment that has caused customer outages due to
6 thermal violations like the example you gave of Trunk
7 359, correct?

8 A But the question asks to provide, identify all
9 subtransmission redesign and rebuild projects that
10 address equipment that has caused customer outages due to
11 thermal violations like I've described for Trunk 59, yes.

12 Q And you declined to provide any examples, correct, to
13 identify any projects?

14 MS. JOHNSON-BACON: I'm going to object.
15 The proposed exhibit speaks for itself.

16 MR. BZDOK: O.K. I'll move to admit it,
17 86.

18 JUDGE WALLACE: Is there any objection to
19 admitting Exhibit MEC-86?

20 Hearing none, the exhibit is admitted.

21 Q (By Mr. Bzdok): Let's talk about voltage violations for
22 a few minutes.

23 A O.K.

24 Q You discuss voltage violations in your rebuttal on page
25 30, starting on page 30.

1 A Yes.

2 Q In question and answer 37, correct?

3 A Correct.

4 Q O.K. And you, and in -- Schedule 002 contains a list of
5 modeled voltage violations on pages 3 and 4; is that
6 right?

7 A It contains a sample set of data for voltage violations.

8 Q For modeled voltage violations, right?

9 A Correct, per the model, yes.

10 Q O.K. The -- is it correct that a voltage violation, if
11 it occurs, if it -- so now I'm talking about an actual
12 voltage violation. If an actual voltage violation
13 occurs, the impact of that is to the customer's service;
14 is that right?

15 A I believe I addressed that in the rebuttal.

16 Q Bear with me a second. So you're looking at page 30,
17 lines 7 to 10, if a system voltage falls outside the
18 required range, the customer's equipment, you give
19 examples, will not function properly and may cause damage
20 operating at these levels, correct?

21 A Correct.

22 Q When you refer to damage operating at these levels,
23 you're referring to the customer's equipment or the
24 utility's equipment?

25 A Reference the customer's equipment.

1 Q A low voltage violation is not an issue of burning out or
2 otherwise harming the utility's system; is that right?

3 A It could be conditions based, like again, unique
4 situations that could impact the DTE Electric equipment
5 also, but under, when we're operating under low voltage
6 or high voltage conditions.

7 Q Those would be unique or rare instances, and in general,
8 this is not an issue for harm to the utility's equipment;
9 would you agree?

10 A Again, we have to go case by case, have to take a look.
11 There are instances where under, based on the
12 configuration, operating outside of the defined voltage
13 range could cause damage to the Company's equipment.

14 Q How would that occur, for instance?

15 A I guess I have to take a look at an example to
16 understand, to share with you.

17 Q You can't think of any examples you could give me of how
18 a low voltage violation could harm a utility's equipment
19 offhand?

20 A Not at the time of my head right now, I'd have to go back
21 and reference the cases.

22 Q O.K. You agree that low voltage violations in some cases
23 can be addressed with additional equipment as opposed to
24 a rebuild?

25 A Can you give me an example?

1 Q So I'm asking, so I'm asking, I don't operate
2 distribution systems, I'm asking you in your position and
3 on your expertise and as the sponsor of these projects,
4 whether, to your knowledge, there are scenarios where low
5 voltage violations can be addressed with the addition of
6 equipment short of a rebuild, are you aware that that is
7 a thing that is true?

8 A Yes, we can solve low voltage issues with adding
9 additional equipment to the system.

10 MR. BZDOK: I'm going to move to admit
11 just -- I'm going to just state without additional
12 questions that we have a Discovery Response MEC-88, which
13 is Discovery Request 17.10, and Response 17.10,
14 MNSCDE-17.10, which is a request and response related to
15 this portion of Mr. Deol's testimony, and I'll move to
16 admit it at this time.

17 JUDGE WALLACE: Is there any objection to
18 admitting Exhibit MEC-88?

19 Hearing none, the exhibit is admitted.

20 Q (By Mr. Bzdok): The numbers in pages 3 and 4 of Exhibit
21 A-50 Schedule 002, those are not actual low voltage
22 violations that have occurred, but rather those are
23 modeled violations, modeled projected violations; would
24 you agree?

25 A That data there include our system analysis, again, we
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1 discussed this, peak load conditions under normal
2 operations or under N-1 contingencies highlighting the
3 issues or concerns that you can see on the system.

4 Q They're not actual violations that have occurred,
5 correct?

6 A Simulating the weak points under that N-1 at
7 (inaudible) --

8 COURT REPORTER: I'm sorry. N-1 what
9 scenario?

10 A At system peak load, projected system peak load at N-1
11 contingency scenario.

12 COURT REPORTER: Thank you.

13 Q (By Mr. Bzdok): Thank you. So in my haste earlier to
14 admit some discovery response exhibits, I failed to ask
15 you a couple of questions, so I'm going to ask you a
16 couple of questions that are sort of out of the blue. If
17 you want to look at a discovery response, you could look
18 at Exhibit MEC-80 because the question is about
19 reliability in the 4.8 and 13.2 kV circuit, so I'm just
20 doing a quick Q&A out of order.

21 A O.K., I'm looking at it.

22 Q Which types of circuits, on general principles and
23 understanding there's variability, on general principles,
24 which type of circuit, 4.8 or 13.2, typically has more
25 customers?

1 A Subject to check, it would be the 13.2.

2 Q To the extent you have any knowledge regarding this, not
3 because it's your direct responsibility but just in your
4 work in the distribution operations area generally, are
5 you aware of whether the Company's procedure during
6 storms is to restore circuits where possible with the
7 most customers out of service first?

8 A When we're in a storm situation, it varies. The first
9 priority for storm is to ensure that we protect the
10 downed conductors. Once we've achieved that, we believe
11 that we've eliminated that public hazard risk and the
12 risk to our employees, then we would start the
13 restoration process.

14 Q With -- and when you've stabilized the safety situation,
15 is the order of restoration typically prioritize circuits
16 serving more customers first?

17 A Actually, the priority would be based on where the damage
18 is that we can fix faster, to restore based on that. So
19 if I can --

20 Q O.K.

21 A -- restore this section, I pick up say a thousand
22 customers versus I could have more customers on this
23 particular section, but the damage is heavily, heavily
24 damaged that it's going to take me longer to restore it
25 all to pick up any customers, so that's going to -- we're

1 going to devote resources to that, but we know that's
2 going to take that longer, so, in essence, to get
3 customers back, we're going to go try to get the most
4 customers that we can get back on the fastest with the
5 least amount of damage that we can repair in the quickest
6 timeframe.

7 Q O.K. Thank you.

8 MR. BZDOK: I have one more topic of
9 length, one more topic that has some length --

10 COURT REPORTER: You froze, Chris. I'm
11 sorry, Chris, you were frozen. I have you said, I have
12 one more topic, and then I don't have anything.

13 MR. BZDOK: O.K.

14 COURT REPORTER: That might be me that
15 did that, but anyway. O.K.

16 MR. BZDOK: Was I frozen for anyone else?

17 JUDGE WALLACE: Yes, you were.

18 COURT REPORTER: O.K. I feel better.

19 MR. BZDOK: O.K. So I have one more
20 substantive topic, but before I do that, I want to move
21 to admit some discovery response exhibits that were also
22 admitted by Mr. Deol in Case U-21297, and those are all
23 loaded in the SharePoint, and they are MEC Exhibit
24 MEC-92, MEC-97, MEC-98, MEC-103, and that's it. So those
25 are the MEC exhibit numbers from this case of discovery

1 responses that were also admitted as exhibits in 21297.

2 JUDGE WALLACE: Thank you. Is there any
3 objection to the admission of Exhibits MEC-92, MEC-97,
4 MEC-98, or MEC-103?

5 Hearing none, those exhibits are
6 admitted.

7 MS. JOHNSON-BACON: Based on Mr. Bzdok's
8 representation that they were admitted as exhibits in
9 21297, no objection from the Company.

10 JUDGE WALLACE: Thank you.

11 MR. BZDOK: Thank you.

12 Q (By Mr. Bzdok): So I next want to talk about, and this
13 should be my last substantive topic, I want to talk
14 about, Mr. Deol, your rebuttal testimony to Mr. Stephens
15 in the very general category of project costs and project
16 approvals, and I will get a page reference in a moment.
17 I'm looking at your rebuttal testimony, starting at page
18 12, questions and answers 19 and 20 relative to Almont
19 a/k/a Midas project as a starting point, and then I want
20 to look at Exhibit A-12 Schedule B5.4, and I think this
21 project is on line 41.

22 MS. JOHNSON-BACON: Chris.

23 MR. BZDOK: Yeah.

24 MS. JOHNSON-BACON: Before we get into
25 this topic, can we take a quick break here?

1 MR. BZDOK: Yeah, it's O.K. with me.

2 JUDGE WALLACE: Yeah. O.K. Let's take
3 15 minutes.

4 MS. JOHNSON-BACON: Sounds good.

5 JUDGE WALLACE: O.K. All right. Fifteen
6 minutes. Off the record.

7 (Recess from 2:12 p.m. until 2:31 p.m.)

8 JUDGE WALLACE: Back on the record.
9 Please continue, Mr. Bzdok.

10 COURT REPORTER: You're muted, Chris.

11 MR. BZDOK: Thanks, Lori.

12 JUDGE WALLACE: And your hand's --

13 MR. BZDOK: What did you say?

14 JUDGE WALLACE: Is your hand up? No,
15 it's the back of your chair.

16 Q (By Mr. Bzdok): Mr. Deol, prior to that break, we had
17 just begun talking about your rebuttal testimony,
18 questions and answers 20 and 21.

19 A O.K.

20 Q And I'm not sure we even started to look at it yet, so
21 I'm just going to start now. You indicate in answer 20
22 in responding to Witness Stephens, you make the statement
23 that: The Midas project example that Witness Stephens
24 uses in his direct testimony demonstrates there is
25 transparency across the documents presented by the

1 Company in the instant case, correct? You see that
2 testimony?

3 A Can you point me to the line?

4 Q Starting at line 10, answer 20, starting at line 10. At
5 this point I'm just referring you to this testimony where
6 you begin to discuss transparency across documents as
7 represented by the Midas example.

8 A O.K.

9 Q O.K. And you indicate that, that something called the
10 CARF, the C-A-R-F, identifies an updated project forecast
11 for the Midas project of \$30.7 million, correct?

12 A No. The CARF was approved in whatever timeframe that's
13 listed on there. What we had stated is the Exhibit 23 M6
14 for that project has that number in there.

15 Q So I'm looking at your Figure 1 on the next page, page
16 14.

17 A Yes.

18 Q Is that the document you're referring to just now?

19 A Yes, that's the document.

20 Q O.K. A CARF is a Company Approval Request Form, is that
21 right, or a Corporation Request Form?

22 A Per my testimony on page 12, line 17, it defines what a
23 CARF is, it's a Capital Appropriation Request Form.

24 Q O.K. So on Figure 1 of your rebuttal on page 14, you
25 identify a total project request of \$30.3 million, you

1 have a little square around it, right?

2 A That 30.7 demonstrates what the estimated cost is to, for
3 that project itself.

4 Q So I don't want to get hung up on a small point here, but
5 I think I might be misunderstanding you. So in your
6 rebuttal testimony on page 13, lines 17 to 19 --

7 A Yes.

8 Q -- you refer to a \$30.3 million figure in Figures 1 and
9 2, and an updated project forecast of \$30.7 million,
10 correct?

11 A Correct.

12 Q And Figure 1 has the \$30.3 million, not 30.7 million,
13 right?

14 A Correct.

15 Q And Figure 2 has the 30.7 million figure; is that right?

16 A Correct.

17 Q That's the -- Figure 1 is from the Appropriation Request
18 Form, Figure 2 is from Exhibit A-23 Schedule M6 in this
19 case, right?

20 A Correct.

21 Q O.K. And then you indicate in that rebuttal testimony on
22 page 13 in the paragraph starting in line 17, and really
23 starting on line 19, you provide the amounts for the
24 Midas project in Exhibit A-12 Schedule B5.4, correct?

25 A Yes, we do describe that.

1 Q And you provide amounts for the years 2022 through 2025
2 totaling \$24.1 million, correct?

3 A Yes. I believe those are the same figures on Schedule,
4 Exhibit A-12 B4 -- B5.4, sorry.

5 Q Yep. Line 41.

6 A Yep, line 41.

7 Q And you indicate that those figures total \$24.1 million,
8 correct?

9 A Correct.

10 Q And then you indicate that the additional spends, in
11 other words, that there were additional spends that are
12 prior to the years depicted on Exhibit A-12 B5.4, but
13 that were depicted on exhibits in the prior two rate
14 cases, 21297 and 20836, correct?

15 A Correct.

16 Q And those spends are \$5.6 million and \$0.5 million,
17 correct?

18 A Correct.

19 Q And so if I pull in those spends from the prior cases and
20 add those to the \$24.1 million, I get 30.2 million; is
21 that right?

22 A Correct. So what's missing here from -- this description
23 here is missing the land acquisition costs for the
24 substation, that's not included here.

25 Q O.K. And is that because the land acquisition costs --
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1 well, why is that?

2 A Because we didn't look back far enough because I'm not
3 sure when the land was acquired for this project itself.

4 Q O.K. It would have been further back than what was
5 depicted in the exhibits in 21297 and 20836?

6 A Correct.

7 Q O.K. Do you have access to Exhibit A-23 Schedule M8, the
8 Distribution Grid Plan for 2023?

9 A No, I don't.

10 Q O.K. Do you have access to the share?

11 MS. JOHNSON-BACON: If we could go off
12 the record for just one moment.

13 MR. BZDOK: O.K.

14 JUDGE WALLACE: Off the record.

15 (At 2:40 p.m., brief pause and discussion to locate
16 exhibit.)

17 Q (By Mr. Bzdok): So in -- so I'm just grounding us for a
18 second, in Figure 2 in your rebuttal on page 15, the
19 program is referred to as 4.8 kV CC: Almont Relief and
20 Circuit Conversion (Midas), correct?

21 A Correct, that's the overall initiative, yes.

22 Q O.K. And then in the DGP, A-23 Schedule M8, if I go to
23 page 236 of that exhibit, which is page 235 of that
24 plan --

25 A O.K.

1 Q -- and there I have Exhibit B.3.2 Projected Costs and
2 Timeline for 4.8 kV Conversion Projects; do you see that?

3 A I do see that.

4 Q And there I have a cumulative 2024 to 2028 investment for
5 the Almont Relief and Circuit Conversion project of \$1
6 million all taking place in 2024; do you see that?

7 A I do see that.

8 Q Now, I understand you didn't do the DGP, I'm just
9 wondering, are you able to reconcile -- do you know why
10 your exhibit has 6 million in 2024 and a million in 2025
11 whereas the DGP for the project has 1 million in 2024 and
12 that's it?

13 A I would have to consult with the person that put the
14 table together versus the latest. So what we're filing
15 with the rate case is the latest information that we had
16 versus when the DGP was filed.

17 Q O.K. So just because sometimes we're overly literal, you
18 would have to consult with means you don't know without
19 further consultation what the reason for the difference
20 would be?

21 A I would have to talk to the person that put the table
22 together to understand what their assumptions were. I'm
23 assuming that this was put together before September 2029
24 versus when we filed the rate case in 2024, that there
25 could be a differences in schedule, timing that they have

1 to take into account.

2 Q O.K. Bear with me a second. So what I'm looking for is,
3 I believe we've admitted already through another witness
4 your Exhibit A-12 Schedule B5.4 from 21297, and so that's
5 what I'm looking for, I just need a second. O.K.

6 Actually, it's proposed Exhibit MEC-90 in the SharePoint
7 folder for you. Do you have access to that?

8 A O.K. I was able to relocate that.

9 Q O.K. So on page 10 of that exhibit, line 57, can you
10 locate Almont Relief and Circuit Conversion (Midas), and
11 let me know when you're there.

12 A Just to clarify, you said page 8, right, on that
13 document?

14 Q Page 10.

15 A Oh, sorry. Line 57?

16 Q Yep. So in column G of line 57, I see a projected test
17 year spend for this Almont/Midas project for the 12
18 months ending November 30, 2024, of \$297,000, and
19 understanding there's a one-month difference there, I'm
20 wondering if you have any insight as to the difference
21 between that figure for 2024 and the calendar year
22 projection on the current A-12 B5.4 of \$6 million for
23 calendar year 2024?

24 A Yeah, I would have to go talk to the project manager for
25 this project to understand. I guess could it be timing,

1 could have been maybe other issues and concerns that they
2 ran into when they were doing the project that was
3 unforeseen when we projected this last time.

4 Q O.K. Does the -- what, if any, is your interaction or
5 engagement with, in your role in supporting these capital
6 expenditures in the programs that you sponsor, do you
7 have any engagement or interaction with the results of
8 the Global Prioritization Model used by DTE to rank
9 distribution projects?

10 A Can you please clarify your question?

11 Q Sure, I can try. So there's been other testimony in this
12 case that DTE uses a Global Prioritization Model or GPM
13 to rank by priority distribution capital projects and
14 programs for DTE. Does that seem roughly, generally
15 familiar to you, that that exists?

16 A Yes, I am aware that we have a Global Prioritization
17 Model for our capital spend within distribution
18 operations.

19 Q O.K.

20 MR. BZDOK: May we go off the record for
21 a moment?

22 JUDGE WALLACE: Off the record.

23 (Brief off record at 2:53 p.m.)

24 JUDGE WALLACE: O.K. Back on the record.

25 Q (By Mr. Bzdok): So I think, so I'm just following up on
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1 the question and answer from just before we took a break.
2 In your sponsoring of distribution projects and programs
3 within your areas, do you take into account in any way
4 the results of the GPM?

5 A I guess I still need a little bit more clarity to kind of
6 understand what you're asking me.

7 Q How, if at all, do you factor in the results of the GPM
8 in the determination of distribution capital projects
9 that you present in Exhibit A-12 Schedule B5.4?

10 A Well, the purpose of the model as far as I understand it
11 is to be able to rank which of our projects have the
12 highest priority that we need to do for our system. That
13 is my understanding of the projects, so the assumption is
14 for all the ones that are listed in the schedule or they
15 were deemed to be higher up in the GPM.

16 Q O.K. So the reason I'm asking is that if you look at the
17 DGP that we had up, the A-23 Schedule M8, and you go to
18 page 259, which is Appendix F --

19 A 259?

20 Q 259.

21 A O.K.

22 Q The Almont or Midas project does not appear on that list,
23 and I'm wondering if you have any comment on that?

24 A If I look at that table, that Appendix F, it's listing
25 the top 50 priority, the top 50 strategic programs.

1 Q O.K.

2 A So it's, it could be maybe this is project 51, I don't
3 know, I don't have the bigger list coming across to see
4 where Almont would fall in from that approach.

5 Q O.K. So is it a fair reading of your testimony that the
6 GPM results are not a major factor in the capital
7 projects and programs that you present in the rate case?

8 A I would disagree with that. I would disagree with that.

9 Q Would you agree that it's not a matter of significant
10 awareness or attention by you?

11 A Me personally?

12 Q Yeah.

13 MS. JOHNSON-BACON: I'm going to object.
14 I think that mischaracterizes Mr. Deol's former
15 testimony. He said that's how projects were prioritized.

16 JUDGE WALLACE: Mr. Bzdok, can you
17 rephrase your question?

18 MR. BZDOK: Sure.

19 Q (By Mr. Bzdok): So I guess what I'm trying to understand
20 as a general matter is, in planning projects,
21 distribution capital projects and programs within the
22 areas of your responsibility, what, what role in your
23 process does the GPM have, if any?

24 A Which process are you referring to?

25 Q The GPM results.

1 MS. JOHNSON-BACON: I'm going to object
2 again. He answered that question. He indicated it's how
3 the projects are prioritized.

4 MR. BZDOK: So he said that's how they're
5 prioritized, and I'm trying to understand what -- and my
6 question was not about how somebody may prioritize them,
7 but about what he does. So it is a different question.

8 MS. JOHNSON-BACON: I'm sorry, Judge, it
9 sounds like the same question to me.

10 JUDGE WALLACE: I kind of get what you're
11 saying, Mr. Bzdok. You want to know how the GPM, the
12 Global Prioritization Model, is used by Mr. Deol --

13 MR. BZDOK: Yep, if at all.

14 JUDGE WALLACE: -- in deciding which, if
15 at all, in deciding which distribution projects to do in
16 the area that he addresses, correct?

17 MR. BZDOK: Correct.

18 JUDGE WALLACE: Is that what we're trying
19 to get at?

20 MR. BZDOK: Yep.

21 A I'm still confused on what you're asking me.

22 Q (By Mr. Bzdok): Is the GPM list a list you consult
23 regularly in the preparation of your distribution capital
24 exhibits?

25 A I consult the GPM list as we're going through our
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1 (inaudible) --

2 COURT REPORTER: Through our what
3 process?

4 A Capital approval process.

5 Q (By Mr. Bzdok): O.K. I want to look at one other
6 project, and then I'm going to let you go, and my
7 reference for you will be your direct testimony, page 36.

8 MS. JOHNSON-BACON: Sorry, Chris, could
9 you repeat that page?

10 MR. BZDOK: 36.

11 MS. JOHNSON-BACON: Thank you.

12 A O.K. I'm looking at it.

13 Q (By Mr. Bzdok): This is a City of Detroit or CODI
14 Infrastructure project. Let me rephrase that question.
15 This is a City of Detroit Infrastructure or CODI project,
16 C-O-D-I, correct?

17 A This table has projects, yes, within the CODI initiative,
18 the City of Detroit initiative.

19 Q Thank you. And the one at the top is the Islandview
20 Substation, correct?

21 A (Nodding).

22 Q Did you say correct?

23 A Yes, correct.

24 Q O.K. This project will serve seven primary service
25 customers, is that right, on the riverfront?

1 A I have to go find my description in my Exhibit A-23 M6,
2 I'm trying to locate what page it is.

3 Q O.K. So I'm looking at pages 200 -- oh, no, that's the
4 wrong one. I'm looking at pages 156 through 167.

5 A O.K. I'm on page 156 on Exhibit A-23 Schedule M6.

6 Q So to clarify, I had asked you a question of whether you
7 knew this project was going to serve three -- I'm
8 sorry -- serve seven primary service customers on the
9 riverfront, and you indicated you needed to consult your
10 exhibit and you weren't sure what page, so I just was
11 giving you the page, but I don't have a question specific
12 to those pages for you, I was just trying to help you
13 along.

14 A Thank you. Unfortunately, I can't tell that from the
15 exhibit that I have, it doesn't describe, it describes
16 the purpose of why we're doing it, it does not go into
17 that detail.

18 Q O.K. Give me a second. In your, in that folder for your
19 hearing room exhibits for us, there are Exhibits MEC-108,
20 109, and 110, which are project-approval related
21 documents, and if you look at 110, page 1, that's where I
22 got the downtown riverfront area and that's where I got
23 the seven primary service customers, under project
24 description and approval.

25 A Navigating my way there.

1 Q Sure.

2 A It's Exhibit 110, correct?

3 Q Yeah.

4 A Because I just quickly looked at it and did not come
5 across what you were stating.

6 Q So Exhibit 110, page 1, about halfway down there's a box,
7 project description and approval.

8 A O.K.

9 Q And I was looking at the second sentence of that
10 paragraph: This work is being driven by increased
11 commercial/industrial load along the downtown riverfront
12 area, future PLD conversions, and limitations of
13 throwover between Walker and Pulford. Do you see that?

14 A I do see that.

15 Q And then there's a reference to various conductor and
16 cable stats?

17 A Right.

18 Q And there's one reference there to four primary service
19 customers and another reference to seven primary service
20 customers; do you see that?

21 A I do see it, but let me understand the way this is
22 written.

23 Q Please, take your time. I'm now thinking what this means
24 is there's 11 primary service customers, 4 will be on
25 underground and 7 will be overhead, but you let me know

1 what the real answer is.

2 A Can you -- I guess can you ask me what the question, the
3 initial question was here?

4 Q I was just trying to lay some context for this project
5 and indicate that it's a project on the riverfront that
6 will serve, I originally said 7 but I'm now thinking
7 maybe it's 11 primary service customers; is that
8 consistent with your understanding?

9 A No.

10 Q O.K. Correct me.

11 A I guess my understanding here is we're having issues or
12 concerns with Walker and Pulford that are supporting this
13 area, so this project is there to be able to start being
14 the source, the 13.2 source for that particular area and
15 start the conversion process, and then we take load from
16 Walker and Pulford, decommission those, and in that
17 process, we have primary customers there that that's
18 alluding to.

19 Q O.K. Got it. And based on your direct testimony in that
20 Table 3, the timeline for this project is 11 years,
21 stretching from 2020 to 2031; is that right?

22 A It is, per all the steps that are listed in the middle
23 box there.

24 Q In your Exhibit A-12 Schedule B5.4 page 14, this project
25 is listed in three phases; is that right?

1 A Which -- sorry, repeat that for me. I couldn't keep up
2 with you there.

3 Q Sorry. Just trying to get you out of here.

4 A Appreciate that.

5 Q I know it's been a long day.

6 A So we're back to the capital schedule?

7 Q Yeah.

8 A O.K. What page were you referring to?

9 Q Page 14.

10 A Page 14.

11 Q Lines 31 to 33. I'm seeing CODI Islandview Substation
12 listed in three different phases.

13 A Yes, I do see those.

14 Q O.K. And likewise, in, when we were looking at your
15 Exhibit A-23 Schedule M6 --

16 A Yes.

17 Q -- that also presents the CODI Islandview Substation
18 project in three phases, right?

19 A Correct.

20 Q In A-23 M6, page 159, there's a total project cost for
21 Phase 1 of \$23,927,471, right?

22 A Yeah, that the estimated project cost to complete it,
23 Phase 1, correct.

24 Q O.K. In A-12 B5.4, there's historic spending for 2022 of
25 \$12,255,000; for 2023, \$7,734,000; and then bridge

1 period -- O.K. Sorry, strike the part about bridge
2 period -- and then there's \$7,000 in 2024, right?

3 A Correct.

4 Q And those add up to, give or take, I don't know, \$20
5 million; is that right?

6 A Yep, adding those two up, approximately 20 million.

7 Q So is the other 4 million earlier in time than 2022 or is
8 it later in time than the 2025 projected test year?

9 A It would -- it is earlier in time, like I said, like the
10 analysis that we did for Almont, I would have to go back
11 and do analysis through the previous rate cases to fully
12 understand it, but at the state where Islandview is in,
13 it has to be in the previous years.

14 Q O.K. We're going to do the same thing for Phase 2 and
15 Phase 3. Phase 2 in A-23 M6, page 163 --

16 MS. JOHNSON-BACON: Is it O.K. if we take
17 a break before we go on to the next?

18 MR. BZDOK: Yep.

19 JUDGE WALLACE: Sure. Off the record for
20 ten minutes.

21 MS. JOHNSON-BACON: Thank you.

22 (Recess from 3:17 p.m. until 3:33 p.m.)

23 JUDGE WALLACE: Back on the record.

24 Please continue, Mr. Bzdok.

25 MR. BZDOK: Thank you, your Honor.

1 Q (By Mr. Bzdok): Mr. Deol, before the break, I'm not sure
2 exactly where we landed, but the question I had hoped to
3 ask you, and maybe I did or maybe I didn't yet, was that
4 per Exhibit A-23 Schedule M8, there's an estimated
5 project cost for Phase 2 of the Islandview project of \$59
6 million and change; is that right?

7 A Yes, that's what's listed on the schedule.

8 Q And the spending for the, that Phase 2 project on your
9 Exhibit A-12 Schedule B5.4, line 32, more or less adds up
10 to something very close to that, would you agree, high
11 level?

12 A Yeah, just simple math, yeah, I would agree.

13 Q Now, Phase 3 of this Islandview project on A-23 Schedule
14 M6, page 167, is estimated at \$65 million and change;
15 would you agree?

16 A Correct.

17 Q And then on Exhibit A-12 Schedule B5.4, Phase 3 on line
18 33 has only one expenditure entry, and that's a historic
19 expenditure for the year ended December 31, 2022, of
20 \$45,000; is that right?

21 A Hold on, I'm getting back to that one.

22 Q O.K.

23 A Yes, that's what the schedule indicates.

24 Q Is the -- what can you do for \$45,000, is it like a
25 predesign or permitting?

1 A Yeah, it could be. Actually, it's probably just a quick
2 some sort of an assessment, some concern, maybe we were
3 shutting down or maybe they needed just another, a look
4 at the route that we wanted to plan or something like
5 that, it's something very simple to, just to understand
6 the project a bit more.

7 Q O.K. The \$65 million for Phase 3, is that spending that
8 is more deeper in the past than 2022 or farther in the
9 future than 2025?

10 A That's future spend.

11 Q Farther in the future than 2025?

12 A Correct.

13 Q The Exhibit A-12 B5.4 has an in-service date for Phase 3
14 of 2025. Do you see that?

15 A I see that.

16 Q How is that possible with no spending?

17 A I'm going to have to go investigate the schedule. Could
18 be an error on the schedule, could be an error on the
19 B-12 E4 -- B5.4 schedule.

20 Q O.K. In the, in the DGP, which was A-23 Schedule M8 --

21 A O.K.

22 Q -- page 211 of the exhibit, which is page 210 of the
23 plan --

24 A 210 of the plan. O.K. I'm on page 210.

25 Q -- that has some bullet point information about CODI

1 Islandview Substation and Walker Conversion, correct?

2 A Are you talking about, I guess on the index column says
3 No. 8, Walker, Detroit, is that what you're referring to?

4 Q Yes.

5 A Yes, it does say Islandview Substation and Walker
6 Conversion.

7 Q And it has a four-bullet-point description of the project
8 at a high level, right?

9 A High level, yes.

10 Q I believe that Islandview does not appear anywhere else
11 in the Distribution Grid Plan. Do you have any reason to
12 disagree with me?

13 A I guess I would have to read the whole plan to state
14 whether I agree with you or disagree with you, I have not
15 read it end to end.

16 Q You don't have a specific reason to think I'm wrong about
17 that?

18 A I would have to verify it. If I'm going to say that's
19 correct or right, I would want to do it myself to state
20 that's true or not.

21 Q O.K. It -- bear with me a second. Appendix F in the
22 DGP, that top 50 list, which is again page 259 of the
23 exhibit, page 258 of the plan, my question for you when
24 you get there, Islandview does not appear in the top 50;
25 is that correct?

1 A Yeah, I do not see it listed in the appendix.

2 Q We had mentioned earlier I think -- well, take a look at
3 Exhibit MEC-107.

4 A O.K. I have it pulled up.

5 Q 107 is a request for approved capital project
6 authorizations for each of 138 distribution projects,
7 generally speaking, and in the response, the Islandview
8 projects appear in the list on page 4 of the exhibit as
9 attachments. My question at this point is, can you see
10 those, there are Attachments 33 through 35?

11 A Yes, I see there's three Islandview phases listed on
12 there.

13 Q O.K. And these are the, these are the CARF documents
14 which we had already pulled up as Exhibits MEC-108,
15 MEC-109, and MEC-110?

16 MS. JOHNSON-BACON: I'm just going to
17 object, Chris, on the basis of foundation. This is a
18 discovery response from Witness Kryscynski?

19 MR. BZDOK: Yep.

20 MS. JOHNSON-BACON: You can respond if
21 you know.

22 A No, I haven't seen the CARFs for these projects.

23 Q (By Mr. Bzdok): So my question is, CARFs were provided
24 for Phase 1 and for Phase 2; 108 is for Phase 1, and 109
25 and 110 are for Phase 2. Do you know if Phase 3 has been

1 approved?

2 A I'd have to go -- I guess I would have to go confer and
3 check to see where we are in the appropriation process
4 for Phase 3. I don't know off the top of my head, I
5 don't.

6 Q O.K. Exhibit MEC-111 is a set of discovery responses
7 from you, 15.33a, a 5.33b, and 8.12a; do you see those?

8 A Yes, I do see those.

9 Q O.K. And these relate to the Islandview and Almont a/k/a
10 Midas projects?

11 A This response, as far as I am interpreting it or
12 understanding it, is just for the construction of the new
13 substation portion of the overall initiative.

14 MR. BZDOK: O.K. Your Honor, I'm going
15 to move at this time for the admission of a bunch of
16 exhibits, those being MEC-107 through MEC-118, and I'm
17 happy to go through those, I'm also -- some of them we've
18 already opened up and touched on, they all deal this
19 topic. So --

20 MS. JOHNSON-BACON: I am, I think as I
21 stated earlier, your Honor, objecting to the admission of
22 109, due to lack of foundation.

23 JUDGE WALLACE: 109 is a discovery
24 response from Mr. Kryscynski?

25 MS. JOHNSON-BACON: Correct.

1 MR. BZDOK: 109, I believe -- go ahead.

2 JUDGE WALLACE: Yeah, I don't -- I --

3 it's fine, we don't need a witness to shepherd that

4 document, it's a discovery response, so it's fine.

5 MS. JOHNSON-BACON: O.K.

6 JUDGE WALLACE: Unless you know it's

7 somehow not authentic, but it was signed by the Company,

8 Company witness, even though it wasn't Mr. Deol, so. All

9 right, 107 through 118?

10 MR. BZDOK: Yes. Yes. So 107 through
11 110 are the discovery response that we just discussed and
12 the three attachments that relate to Islandview; 111 is
13 the Discovery Responses 15.33a and b and 8.12a that we
14 just discussed having to do with substations for
15 Islandview and Almont; 111 through -- sorry -- yeah, 112
16 through 118 are the historic exhibits from the prior rate
17 cases that Mr. Deol said would have -- could have
18 historic spending amounts for dollars for these projects
19 not included in his current capital exhibit that would
20 have to be dug through, and so that's the capital
21 exhibits and the M6es and M5s, M6 used to be M5, so
22 that's what that is.

23 MS. JOHNSON-BACON: These were admitted
24 as exhibits in the prior cases, Chris?

25 MR. CHRISTINIDIS: These excerpts of
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1 things that were admitted of Company exhibits from the
2 prior cases.

3 MS. JOHNSON-BACON: Thank you.

4 JUDGE WALLACE: All right. Is there any
5 objection to, further objection to the admission of
6 Exhibits MEC-107 through MEC-118?

7 Hearing none, those exhibits are
8 admitted.

9 MR. BZDOK: Thank you. Your Honor, I
10 need a moment, I am at the end of my outline for
11 Mr. Deol, but I need to just check my notes and confer
12 briefly. It may also be a time for the Company to confer
13 and, not to tell them their business. I can either go
14 off two minutes and we can come back --

15 JUDGE WALLACE: Is there anybody else
16 here who's got questions for Mr. Deol? (No response.)

17 O.K. Five minutes off the record, and
18 then we'll come back, and then if you've got redirect,
19 Ms. Johnson-Bacon, we'll take care of that as well.

20 MS. JOHNSON-BACON: Thank you.

21 (Recess from 3:51 p.m. until 4:00 p.m.)

22 JUDGE WALLACE: All right. Back on the
23 record. Mr. Bzdok, did you have any additional questions
24 or --

25 MR. BZDOK: I have one or two more

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1 questions, then I'm going to move for the admission of
2 two more exhibits.

3 JUDGE WALLACE: Please proceed.

4 Q (By Mr. Bzdok): So Mr. Deol, I understand that you are
5 not familiar with the specific CARF approval forms for
6 Islandview that we admitted as MEC-108, 109, and 110. I
7 do want to ask you one question. So there was a
8 reference in one of them, and I just want to ask you a
9 question about whether you have independent or separate
10 knowledge about a certain item. And so if you would look
11 at 108, MEC-108, which is MNSCDE-8.5c(S1) Attachment 33.

12 A O.K., I have it up.

13 Q O.K. In the box titled Project Description and Approval,
14 there's a reference -- there's a paragraph and then a
15 sentence following the, you know, below the paragraph.
16 So the last sentence in the paragraph says: The
17 Initiative includes seven distinct, independent projects
18 executed over the next ten years. My only question is,
19 do you see that sentence?

20 A I do see that sentence.

21 Q Do you know anything about, separate from this form, do
22 you know anything about Islandview consisting of seven
23 projects?

24 A I guess I would have to go back and look at the time when
25 this was approved and signed what this was referring to

1 regarding the seven distinct projects.

2 Q O.K. Do you have any knowledge as to whether there will
3 be more than three phases for CODI Islandview?

4 A Per my current understanding, there's three phases for
5 this project, as stated and provided in Exhibit 23
6 Schedule M6 part of my testimony.

7 MR. BZDOK: O.K. Your Honor, at this
8 time I'm going to offer proposed Exhibit MEC-90, which is
9 Exhibit A-12 Schedule B5.4 from U-21297, which is a
10 document we talked about earlier in this exam and Lori
11 reminded me I had failed to move for it.

12 JUDGE WALLACE: Is there any objection to
13 the admission of Exhibit MEC-90?

14 Hearing none, the exhibit is admitted.

15 MR. BZDOK: And I'm also going to move
16 for the admission of Exhibit MEC-106 proposed, which was
17 Discovery Response 17.7, at the Company counsel's
18 request.

19 JUDGE WALLACE: All right. Is there any
20 objection to the admission of Exhibit MEC-106?

21 Hearing none, the exhibit is admitted.

22 MR. BZDOK: Mr. Deol, I know it has been
23 a long road, I appreciate your time and your answers, and
24 I have no further questions for you.

25 THE WITNESS: All right.

1 MR. BZDOK: Thank you.

2 JUDGE WALLACE: Thank you, Mr. Bzdok.

3 Ms. Johnson-Bacon, do you have any redirect for Mr. Deol?

4 MS. JOHNSON-BACON: The Company has no
5 redirect for Mr. Deol. Thank you.

6 JUDGE WALLACE: Thank you. All right.
7 Well, thank you very much, Mr. Deol, for putting up with
8 us all day, and you are excused.

9 THE WITNESS: All right. Thank you.

10 (The witness was excused.)

11 - - -

12 JUDGE WALLACE: And let's go off the
13 record for a couple minutes.

14 (Off-record discussion, 4:06 p.m. until 4:13 p.m.)

15 JUDGE WALLACE: Back on the record. Off
16 the record we were discussing organizing cross for
17 tomorrow, it's our last day. Two witnesses for sure, and
18 then we'll be binding in the Company's case and some
19 intervenors, and then back in the afternoon to bind in
20 everybody else, including Staff. So if anything comes
21 up, you can always email me, I'm around. And with that,
22 we are adjourned for today. Thank you, all, very much.

23 MR. CHRISTINIDIS: And your Honor, we
24 start at 9:00; is that right?

25 JUDGE WALLACE: Yes.

1 MR. CHRISTINIDIS: Thank you.

2 (Collective "Thank you.")

3 (At 4:14 p.m., the hearing adjourned to Tuesday,

4 September 10, 2024, for continued cross-

5 examination.)

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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 Monday,
September 9, 2024; and do further certify that the
foregoing transcript, consisting of Volume 5 PUBLIC
RECORD, pages 1116-1393, constitutes a true and correct
transcript of my stenotype notes.



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Dated: September 10, 2024